Designated Original per PM

Entergy

Entergy Operations, Inc.
River Bend Station
5485 US Highway 61
St. Francisville, LA 70775
Tel 225 381 4374
Fax 225 381 4872
mperito@entergy.com

Michael Perito
Vice President, Operations
River Bend Station

RBG-46932

August 10, 2009

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555-0001

SUBJECT: License Amendment Request 2009-05
24-Month Fuel Cycles
River Bend Station – Unit 1
Docket No. 50-458
License No. NPF-47

REFERENCES: (1) Generic Letter 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24-Month Fuel Cycle," dated April 2, 1991

(2) Regulatory Guide 1.52, "Design, Inspection, and Testing Criteria for Air Filtration and Adsorption Units of Post-Accident Engineered Safety Feature Atmospheric Cleanup Systems in Light-water Cooled Nuclear Power Plants," Revision 2, March 1978

(3) Regulatory Guide 1.197, "Demonstrating Control Room Envelope Integrity at Nuclear Power Reactors," Revision 0, May 2003

RBF1-09-0079
File No.: G9.5

Dear Sir or Madam:

Pursuant to 10 CFR 50.90, Entergy Operations, Inc. hereby requests an amendment to Appendix A, Technical Specifications (TS), of Facility Operating License No. NPF-47 for River Bend Station – Unit 1 (RBS) to support operation with 24-month fuel cycles. Specifically, the change addresses certain TS Surveillance Requirement (SR) frequencies that are specified as "18 months" by revising them to "24 months" in accordance with the guidance of Generic Letter (GL) 91-04, (Reference 1).

Also consistent with this guidance, a change is proposed to Administrative Controls Sections 5.5.7, "Ventilation Filter Testing Program (VFTP)," to address changes to 18 month frequencies that are specified in Regulatory Guide (RG) 1.52, "Design, Inspection, and Testing Criteria for Air Filtration and Adsorption Units of Post-Accident Engineered-Safety-Feature Atmosphere Cleanup Systems in Light-Water-Cooled Nuclear Power Plants," (Reference 2), and Section 5.5.14, "Control Room Envelope

A001
NRR

Habitability Program," to address changes to 18 month frequencies that are specified in RG 1.197, "Demonstrating Control Room Envelope Integrity at Nuclear Power Reactors," (Reference 4). Also, Entergy proposes to change the Technical Specification allowable values for loss of power instrumentation (TS 3.3.8), as well as the standby liquid control available Boron-10 weight (TS 3.1.7).

The information supporting the proposed TS changes is subdivided as follows:

- Attachment 1 provides our evaluation supporting the proposed changes
- Attachment 2 contains copies of the marked up TS pages
- Attachment 3 contains copies of the marked up Bases pages (for information only)
- Attachment 4 summarizes formal licensee commitments pending NRC approval of the proposed amendment
- Attachment 5 provides detailed GL 91-04 evaluation results
- Attachment 6 provides detailed evaluation methods utilized
- Attachment 7 provides a list of applicable instruments within the scope of this amendment request

The proposed changes have been reviewed and approved by the RBS Onsite Safety Review Committee in accordance with 10 CFR 50.91(a)(1) using criteria in 10 CFR 50.92(c), and it has been determined that this change involves no significant hazards consideration. The bases for these determinations are included in the attached submittal.

Entergy requests approval of this change by August 15, 2010. Approval by this date will support scheduling and planning the subsequent refueling outage based on 24 month Surveillance Frequency requirements. Once approved, the amendment will be implemented no later than the end of the next refueling outage (scheduled to begin in January 2011). The implementation period will allow for flexibility in the schedule for needed divisional modifications.

If you have any questions or require additional information, please contact Mr. David Lorfing at 225-381-4157. Commitments identified in this letter are summarized in Attachment 4.

I declare under penalty of perjury that the foregoing is true and correct.

Respectfully,

Michael Perito
Vice President – Operations

Attachments:
1. Evaluation of Proposed Changes
2. Markup of Proposed Technical Specification Page Changes
3. Markup of Proposed Technical Specification Bases Pages (For Information Only)
4. List of Commitments
5. Detailed Evaluation Results
6. Detailed Evaluation Methods
7. Applicable Instrumentation

cc: U. S. Nuclear Regulatory Commission
Region IV
612 East Lamar Blvd., Suite 400
Arlington, TX 76011-4125

NRC Sr. Resident Inspector
P. O. Box 1050
St. Francisville, LA 70775

Mr. Jim Calloway
Public Utility Commission of Texas
1701 N. Congress Ave.
Austin, TX 78711-3326

Mr. Jeffrey P. Meyers
Louisiana Department of Environmental Quality
Attn: OEC-ERSD
P.O. Box 4312
Baton Rouge, LA 70821-4312

U.S. Nuclear Regulatory Commission
Attn: Mr. Alan Wang
Washington, DC 20555-0001

Attachment 1
RBG-46932

Evaluation of Proposed Changes

1.0 DESCRIPTION

This letter proposes to amend Appendix A, Technical Specifications (TS), of Facility Operating License No. NPF-47 for River Bend Station (RBS), Unit 1.

The requested change affects certain TS Surveillance Requirement (SR) frequencies that are specified as "18 months" by revising them to "24 months" in accordance with the guidance of Generic Letter (GL) 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24 Month Fuel Cycle," dated April 2, 1991 (Reference 1). Also consistent with this guidance, a change is proposed to Administrative Controls Sections 5.5.7, "Ventilation Filter Testing Program (VFTP)," to address changes to 18 month frequencies that are specified in Regulatory Guide (RG) 1.52, "Design, Inspection, and Testing Criteria for Air Filtration and Adsorption Units of Post-Accident Engineered-Safety-Feature Atmosphere Cleanup Systems in Light-Water-Cooled Nuclear Power Plants," (Reference 2), and Section 5.5.14, "Control Room Envelope Habitability Program," to address changes to 18 month frequencies that are specified in RG 1.197, "Demonstrating Control Room Envelope Integrity at Nuclear Power Reactors," (Reference 4). Also, Entergy proposes to change the Technical Specification allowable values for loss of power instrumentation (TS 3.3.8), as well as the standby liquid control available Boron-10 weight (TS 3.1.7).

Entergy is requesting approval of this change by August 15, 2010. Approval by this date will support scheduling and planning the subsequent refueling outage based on 24 month surveillance frequency requirements. As demonstrated in this submittal, the proposed changes do not adversely impact safety. The proposed changes are being submitted to the NRC as a Cost Beneficial Licensing Action, and are similar to license amendments issued for a number of other nuclear units. Specifically, the proposed amendment is similar to amendments issued for Clinton Power Station, Perry Nuclear Power Plant, and E.I. Hatch Nuclear Plant.

2.0 PROPOSED CHANGES

2.1.1 Changes from 18 months to 24 months

To accommodate a 24-month fuel cycle for RBS, certain surveillance frequencies that are specified as "18 months" are being revised to "24 months." The proposed changes were evaluated in accordance with the guidance provided in NRC GL 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24-Month Fuel Cycle" (Reference 1). The following SR frequencies are being revised to 24 months:

<u>TS 3.1.7 Standby Liquid Control (SLC) System</u>

SR 3.1.7.8 Verify flow through one SLC subsystem from pump into reactor pressure vessel.

TS 3.1.8 Scram Discharge Volume (SDV) Vent and Drain Valves

SR 3.1.8.3	Verify each SDV vent and drain valve: a. Closes in $\leq$ 30 seconds after receipt of an actual or simulated scram signal; and b. Opens when the actual or simulated scram signal is reset.

3.3.1.1 Reactor Protection System (RPS) Instrumentation

SR 3.3.1.1.12	Perform CHANNEL FUNCTIONAL TEST.
SR 3.3.1.1.13	Perform CHANNEL CALIBRATION.
SR 3.3.1.1.14	Verify the APRM Flow Biased Simulated Thermal Power-High time constant is within the limits specified in the COLR.
SR 3.3.1.1.15	Perform LOGIC SYSTEM FUNCTIONAL TEST.
SR 3.3.1.1.16	Verify Turbine Stop Valve Closure and Turbine Control Valve Fast Closure Trip Oil Pressure-Low Functions are not bypassed when THERMAL POWER is $\geq$ 40% RTP.
SR 3.3.1.1.17	Calibrate the flow reference transmitters
SR 3.3.1.1.18	Verify the RPS RESPONSE TIME is within limits.

3.3.1.2 Source Range Monitor (SRM) Instrumentation

SR 3.3.1.2.6	Perform CHANNEL CALIBRATION.

3.3.2.1 Control Rod Block Instrumentation

SR 3.3.2.1.8	Perform CHANNEL FUNCTIONAL TEST.

3.3.3.1 Post Accident Monitoring (PAM) Instrumentation

SR 3.3.3.1.3	Perform CHANNEL CALIBRATION.

3.3.3.2 Remote Shutdown System

SR 3.3.3.2.2	Verify each required control circuit and transfer switch is capable of performing the intended functions.
SR 3.3.3.2.3	Perform CHANNEL CALIBRATION for each required instrumentation channel, except valve position instrumentation.

3.3.4.1 End of Cycle Recirculation Pump Trip (EOC-RPT) Instrumentation

SR 3.3.4.1.3	Perform CHANNEL CALIBRATION. The Allowable Values shall be: a. TSV Closure: ≤ 7% closed. b. TCV Fast Closure, Trip Oil Pressure — Low: ≥ 465 psig.
SR 3.3.4.1.4	Perform LOGIC SYSTEM FUNCTIONAL TEST, including breaker actuation.

SR 3.3.4.1.5 Verify TSV Closure and TCV Fast Closure, Trip Oil Pressure-Low Functions are not bypassed when THERMAL POWER is $\geq$ 40% RTP.
SR 3.3.4.1.6 Verify the EOC-RPT SYSTEM RESPONSE TIME is within limits.

3.3.4.2 Anticipated Transient Without Scram Recirculation Pump Trip (ATWS-RPT) Instrumentation

SR 3.3.4.2.4 Perform CHANNEL CALIBRATION. The Allowable Values shall be:

a. Reactor Vessel Water Level−Low Low, Level 2: ≥ -47 inches; and
b. Reactor Steam Dome Pressure−High: ≤ 1165 psig.

SR 3.3.4.2.5 Perform LOGIC SYSTEM FUNCTIONAL TEST, including breaker actuation.

3.3.5.1 Emergency Core Cooling System (ECCS) Instrumentation

SR 3.3.5.1.5 Perform CHANNEL CALIBRATION.
SR 3.3.5.1.6 Perform LOGIC SYSTEM FUNCTIONAL TEST.

3.3.5.2 Reactor Core Isolation Cooling (RCIC) System Instrumentation

SR 3.3.5.2.4 Perform CHANNEL CALIBRATION.
SR 3.3.5.2.5 Perform LOGIC SYSTEM FUNCTIONAL TEST.

3.3.6.1 Primary Containment and Drywell Isolation Instrumentation

SR 3.3.6.1.5 Perform CHANNEL CALIBRATION.
SR 3.3.6.1.6 Perform LOGIC SYSTEM FUNCTIONAL TEST.
SR 3.3.6.1.7 Verify the ISOLATION SYSTEM RESPONSE TIME for the main steam isolation valves is within limits.

3.3.6.2 Secondary Containment and Fuel Building Isolation Instrumentation

SR 3.3.6.2.4 Perform CHANNEL CALIBRATION.
SR 3.3.6.2.5 Perform LOGIC SYSTEM FUNCTIONAL TEST.

3.3.6.3 Containment Unit Cooler System Instrumentation

SR 3.3.6.3.4 Perform CHANNEL CALIBRATION.
SR 3.3.6.3.5 Perform LOGIC SYSTEM FUNCTIONAL TEST.

3.3.6.4 Relief and Low-Low Set (LLS) Instrumentation

SR 3.3.6.4.3 Perform CHANNEL CALIBRATION.
SR 3.3.6.4.4 Perform LOGIC SYSTEM FUNCTIONAL TEST.

3.3.7.1 Control Room Fresh Air (CRFA) System Instrumentation

SR 3.3.7.1.4	Perform CHANNEL CALIBRATION.
SR 3.3.7.1.5	Perform LOGIC SYSTEM FUNCTIONAL TEST.

3.3.8.1 Loss of Power (LOP) Instrumentation

SR 3.3.8.1.3	Perform CHANNEL CALIBRATION.
SR 3.3.8.1.4	Perform LOGIC SYSTEM FUNCTIONAL TEST.

3.3.8.2 Reactor Protection System (RPS) Electric Power Monitoring

SR 3.3.8.2.2	Perform CHANNEL CALIBRATION.
SR 3.3.8.2.3	Perform a system functional test.

3.4.2 Flow Control Valves (FCVs)

SR 3.4.2.1	Verify each FCV fails "as is" on loss of hydraulic pressure at the hydraulic unit.
SR 3.4.2.2	Verify average rate of each FCV movement is: a. ≤ 11% of stroke per second for opening; and b. ≤ 11% of stroke per second for closing.

3.4.4 Safety/Relief Valves (S/RVs)

SR 3.4.4.2	Verify each required relief function S/RV actuates on an actual or simulated automatic initiation signal.

3.4.7 RCS Leakage Detection Instrumentation

SR 3.4.7.3	Perform CHANNEL CALIBRATION of required leakage detection instrumentation.

3.5.1 ECCS - Operating

SR 3.5.1.5	Verify each ECCS injection/spray subsystem actuates on an actual or simulated automatic initiation signal.
SR 3.5.1.6	Verify the ADS actuates on an actual or simulated automatic initiation signal.
SR 3.5.1.8	Verify the ECCS RESPONSE TIME for each ECCS injection/spray subsystem is within limits.

3.5.2 ECCS - Shutdown

SR 3.5.2.6	Verify each required ECCS injection/spray subsystem actuates on an actual or simulated automatic initiation signal.

3.5.3 RCIC System

SR 3.5.3.4	Verify, with RCIC steam supply pressure ≤ 165 psig and ≥ 150 psig, the RCIC pump can develop a flow rate ≥ 600 gpm against a system head corresponding to reactor pressure.
SR 3.5.3.5	Verify the RCIC System actuates on an actual or simulated automatic initiation signal.

3.6.1.2 Primary Containment Air Locks

SR 3.6.1.2.4	Verify, from an initial pressure of 90 psig, the primary containment air lock seal pneumatic system pressure does not decay at a rate equivalent to > 1.50 psig for a period of 24 hours.

3.6.1.3 Primary Containment Isolation Valves (PCIVs)

SR 3.6.1.3.7	Verify each automatic PCIV actuates to the isolation position on an actual or simulated isolation signal.
SR 3.6.1.3.8	Verify in-leakage rate of ≤ 340 scfh for each of the following valve groups when tested at 11.5 psid for MS-PLCS valves.

3.6.1.6 Low-Low Set (LLS) Valves

SR 3.6.1.6.2	Verify the LLS System actuates on an actual or simulated automatic initiation signal.

3.6.1.7 Primary Containment Unit Coolers

SR 3.6.1.7.3	Verify each required primary containment unit cooler actuates throughout its emergency operating sequence on an actual or simulated automatic initiation signal.

3.6.1.9 Main Steam-Positive Leakage Control System (MS-PLCS)

SR 3.6.1.9.3	Perform a system functional test of each MS-PLCS subsystem

3.6.3.2 Primary Containment and Drywell Hydrogen Igniters

SR 3.6.3.2.3	Verify each required igniter in inaccessible areas develops sufficient current draw for a ≥ 1700°F surface temperature.
SR 3.6.3.2.4	Verify each required igniter in accessible areas develops a surface temperature of ≥ 1700°F.

3.6.3.3 Containment/Drywell Hydrogen Mixing Systems

SR 3.6.3.3.2	Verify each Containment/Drywell Hydrogen Mixing System flow rate is ≥ 600 scfm.

3.6.4.1 Secondary Containment-Operating

SR 3.6.4.1.4	Verify each standby gas treatment (SGT) subsystem will draw down the shield building annulus and auxiliary building to ≥ 0.5 and ≥ 0.25 inch of vacuum water gauge in ≤ 18.5 and ≤ 34.5 seconds, respectively.
SR 3.6.4.1.6	Verify each SGT subsystem can maintain ≥ 0.5 and ≥ 0.25 inch of vacuum water gauge in the shield building annulus and auxiliary building, respectively, for 1 hour.

3.6.4.2 Secondary Containment Isolation Dampers (SCIDs) and Fuel Building Isolation Dampers (FBIDs)

SR 3.6.4.2.2	Verify each required automatic SCID and FBID actuates to the isolation position on an actual or simulated automatic isolation signal.

3.6.4.3 Standby Gas Treatment (SGT) System

SR 3.6.4.3.3	Verify each SGT subsystem actuates on an actual or simulated initiation signal.
SR 3.6.4.3.4	Verify each SGT filter cooling bypass damper can be opened and the fan started.

3.6.4.7 Fuel Building Ventilation System - Fuel Handling

SR 3.6.4.7.3	Perform fuel building ventilation charcoal filtration filter testing in accordance with the Ventilation Filter Testing Program (VFTP).
SR 3.6.4.7.4	Verify each fuel building ventilation charcoal filtration subsystem actuates on an actual or simulated initiation signal.
SR 3.6.4.7.5	Verify each fuel building ventilation charcoal filtration filter cooling bypass damper can be opened and the fan started.

3.6.5.1 Drywell

SR 3.6.5.1.2	Verify from an initial pressure of 75 psig, the personnel door inflatable seal pneumatic system pressure does not decay at a rate equivalent to ≥ 20.0 psig for a period of 24 hours.

3.6.5.2 Drywell Air Lock

SR 3.6.5.2.5	Verify, from an initial pressure of 75 psig, the drywell air lock seal pneumatic system pressure does not decay at a rate equivalent to > 20.0 psig for a period of 24 hours.

3.6.5.3 Drywell Isolation Valves

SR 3.6.5.3.5	Verify each automatic drywell isolation valve actuates to the isolation position on an actual or simulated isolation signal.

3.7.1 Standby Service Water (SSW) System and Ultimate Heat Sink (UHS)

SR 3.7.1.5	Verify each SSW subsystem actuates on an actual or simulated initiation signal.

3.7.2 Control Room Fresh Air (CRFA) System

SR 3.7.2.2	Perform required CRFA filter testing in accordance with the Ventilation Filter Testing Program (VFTP).
SR 3.7.2.3	Verify each CRFA subsystem actuates on an actual or simulated initiation signal.
SR 3.7.2.4	Perform required CRE unfiltered air inleakage testing in accordance with CRE Habitability Program.

3.7.3 Control Room Air Conditioning (AC) System

SR 3.7.3.1	Verify each control room AC subsystem has the capability to remove the assumed heat load.

3.7.5 Main Turbine Bypass System

SR 3.7.5.2	Perform a system functional test.
SR 3.7.5.3	Verify the TURBINE BYPASS SYSTEM RESPONSE TIME is within limits.

3.8.1 AC Sources-Operating

SR 3.8.1.8	Verify manual transfer of unit power supply from the normal offsite circuit to required alternate offsite circuit.
SR 3.8.1.9	Verify each DG rejects a load greater than or equal to its associated single largest post accident load and following load rejection, the engine speed is maintained less than nominal plus 75% of the difference between nominal speed and the overspeed trip setpoint or 15% above nominal, whichever is lower.
SR 3.8.1.10	Verify each DG operating at a power factor ≤ 0.9 does not trip and voltage is maintained ≤ 4784 V for DG 1A and DG 1B and ≤ 5400 V for DG 1C during and following a load rejection of a load ≥ 3030 kW and ≤ 3130 kW for DGs 1A and 1B and ≥ 2500 kW and ≤ 2600 kW for DG 1C.

SR 3.8.1.11 Verify on an actual or simulated loss of offsite power signal:

a. De-energization of emergency buses;
b. Load shedding from emergency buses for Divisions 1 and 2; and
c. DG auto-starts from standby condition and:
    1. energizes permanently connected loads in ≤ 10 seconds for DG 1A and DG 1B and ≤ 13 seconds for DG 1C,
    2. energizes auto-connected shutdown loads,
    3. maintains steady state voltage ≥ 3740 V and ≤ 4580 V,
    4. maintains steady state frequency ≥ 58.8 Hz and ≤ 61.2 Hz, and
    5. supplies permanently connected and auto-connected shutdown loads for ≥ 5 minutes.

SR 3.8.1.12 Verify on an actual or simulated Emergency Core Cooling System (ECCS) initiation signal each DG auto-starts from standby condition and:

a. For DG 1C during the auto-start maintains voltage ≤ 5400 V and frequency ≤ 66.75 Hz;
b. In ≤ 10 seconds for DG 1A and DG 1B and ≤ 13 seconds for DG 1C after auto-start and during tests, achieves voltage ≥ 3740 V and ≤ 4580 V;
c. In ≤ 10 seconds for DG 1A and DG 1B and ≤ 13 seconds for DG 1C after auto-start and during tests, achieves frequency ≥ 58.8 Hz and ≤ 61.2 Hz; and
d. Operates for ≥ 5 minutes.

SR 3.8.1.13 Verify each DG's automatic trips are bypassed on an actual or simulated ECCS initiation signal except:

a. Engine overspeed; and
b. Generator differential current;

SR 3.8.1.14 Verify each DG operating at a power factor ≤ 0.9 operates for ≥ 24 hours:

a. For DG 1A and DG 1B loaded ≥ 3030 kW and ≤ 3130 kW; and
b. For DG 1C:
    1. For ≥ 2 hours loaded ≥ 2750 kW and ≤ 2850 kW, and
    2. For the remaining hours of the test loaded ≥ 2500 kW and ≤ 2600 kW.

SR 3.8.1.15 Verify each DG starts and achieves, in ≤ 10 seconds for DG 1A and DG 1B and ≤ 13 seconds for DG 1C, voltage ≥ 3740 V and ≤ 4580 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.

SR 3.8.1.16 Verify each DG:

a. Synchronizes with offsite power source while loaded with emergency loads upon a simulated restoration of offsite power;
b. Transfers loads to offsite power source; and
c. Returns to ready-to-load operation.

SR 3.8.1.17 Verify, with a DG operating in test mode and connected to its bus, an actual or simulated ECCS initiation signal overrides the test mode by:

a. Returning DG to ready-to-load operation; and
b. Automatically energizing the emergency loads from offsite power.

SR 3.8.1.18 Verify the sequence time is within ± 10% of design for each load sequence timer.

SR 3.8.1.19 Verify, on an actual or simulated loss of offsite power signal in conjunction with an actual or simulated ECCS initiation signal:

a. De-energization of emergency buses;
b. Load shedding from emergency buses for Divisions I and II; and
c. DG auto-starts from standby condition and:
    1. energizes permanently connected loads in ≤ 10 seconds for DG 1A and DG 1B and ≤ 13 seconds for DG 1C,
    2. energizes auto-connected emergency loads,
    3. achieves steady state voltage ≥ 3740 V and ≤ 4580 V,
    4. achieves steady state frequency ≥ 58.8 Hz and ≤ 61.2 Hz, and
    5. supplies permanently connected and auto-connected emergency loads for ≥ 5 minutes.

(Note that certain SRs in AC Sources – Operating are currently being reviewed for License Amendment Request 2009-01, submitted on January 21, 2009. The markups in Attachment 2 of this submittal were developed from the current Technical Specifications.)

3.8.4 DC Sources-Operating

SR 3.8.4.3 Verify battery cells, cell plates, and racks show no visual indication of physical damage or abnormal deterioration.

SR 3.8.4.4 Remove visible corrosion, and verify battery cell to cell and terminal connections are coated with anti-corrosion material.

SR 3.8.4.5	Verify battery connection resistance is ≤ 1.5 E-4 ohm for inter-cell connections, ≤ 1.5 E-4 ohm for inter-rack connections, ≤ 1.5 E-4 ohm for inter-tier connections, and ≤ 1.5 E-4 ohm for terminal connections.
SR 3.8.4.6	Verify each battery charger supplies ≥ 300 amps for chargers 1A and 1B and ≥ 50 amps for charger 1C at ≥ 130.2 V for ≥ 8 hours.
SR 3.8.4.7	Verify battery capacity is adequate to supply, and maintain in OPERABLE status, the required emergency loads for the design duty cycle when subjected to a battery service test.
SR 3.8.4.8	Verify battery capacity is ≥ 80% of the manufacturer's rating when subjected to a performance discharge test.

5.5.2 Primary Coolant Sources Outside Containment

b. Integrated leak test requirements for each system at refueling cycle intervals or less.

5.5.7 Ventilation Filter Testing Program (VFTP)

Also, consistent with Reference 1 guidance, a change is proposed to Administrative Controls Section 5.5.7, "Ventilation Filter Testing Program (VFTP)," to address changes to 18 month frequencies that are specified in Reference 2. This change incorporates an explicit exception to the 18 month interval recommended by Reference 2, by revising the first paragraph of TS 5.5.7 as follows (added words shown underlined):

5.5.7 A program shall be established to implement the following required testing of Engineered Safety Feature (ESF) filter ventilation systems at the frequencies specified in Regulatory Guide 1.52, Revision 2, except that testing specified at a frequency of 18 months is required at a frequency of 24 months.

5.5.14 Control Room Envelope Habitability Program

A change is proposed to Administrative Controls Section 5.5.14, "Control Room Envelope Habitability Program," to address changes to 18 month frequencies that are specified in that section. This change revises the following subsection to change "18 months" to "24 months."

d. Measurement, at designated locations, of the CRE pressure relative to all external areas adjacent to the CRE boundary during the pressurization mode of operation by one subsystem of the CRFA System, operating at the flow rate required by the VFTP, at a Frequency of 24 months on a STAGGERED TEST

BASIS. The results shall be trended and used as part of the 24 month assessment of the CRE boundary.

2.1.2 Allowable Value (AV) Changes

In accordance with Reference 1, for calibration interval extensions a comparison of the projected drift errors over the extended calibration interval was made with the values of drift used in the setpoint calculations. In most cases the calculated drift for the 24-Month calibration interval was bounded by the drift values assumed in the setpoint calculations. For those calculations where the calculated drift was not bounded, the calculations were revised to incorporate the calculated drift values. In all cases, except for loss of power instrumentation, the AV was unchanged based on the revised drift number. Additionally, conditions and assumptions of the setpoint and safety analysis were reviewed to validate appropriate acceptance criteria. In all cases, except for loss of power instrumentation, the comparisons and reviews confirmed that the existing Technical Specification Allowable Values were conservative with respect to the projected drift and consistent with safety analysis assumptions.

2.1.3 Standby Liquid Control System

To address future core designs for 24-month cycles, the available weight of Boron-10 in the standby liquid control system is being increased from 143 to 170 pounds-mass. The basis for the new value is the 24-month cycle nominal core design.

3.0 BACKGROUND

3.1 Generic Letter 91-04 Changes

In NRC GL 91-04 (Reference 1), the NRC provided generic guidance for evaluating a 24-month surveillance test interval for TS SRs that are currently performed at 18-month intervals. Section 4.0 that follows defines each step outlined by the NRC in Reference 1 and provides a description of the methodology used by RBS to complete the evaluation for each specific TS SR being extended from 18 months to a 24 month frequency. The methodology utilized in the RBS drift analysis is similar to the methodology used for previous plant submittals such as the Perry Nuclear Power Plant and for E.I. Hatch Nuclear Plant submittals. There have been minor revisions incorporated into the River Bend drift design guide based on NRC comments or Requests for Additional Information from previous 24-Month Fuel Cycle Extension submittals, such as RBS addition of the requirement that 30 samples were generally required to produce a statistically significant sample set.

The proposed TS changes based on Reference 1 have been divided into two categories. The categories are: (1) changes to surveillances other than channel calibrations, identified as "Non-Calibration Changes"; and (2) changes involving the channel calibration frequency identified as "Channel Calibration Changes."

For each component having a surveillance interval extended, historical surveillance test data and associated maintenance records were reviewed in evaluating the effect on safety. In addition, the licensing basis was reviewed for functions associated with each revision to ensure it was not invalidated. Based on the results of these reviews, it is concluded that there is no adverse effect on plant safety due to increasing the surveillance test intervals from 18 to 24 months with the continued application of SR 3.0.2, which allows a 25% extension (i.e., grace period up to 30 months) to SR frequencies.

Additionally, to support some of the above channel calibration changes to a 24-month frequency, setpoint analysis revisions were required, but, except for loss of power instrumentation, did not result in Technical Specification Allowable Value changes.

RBS setpoint calculations, and affected calibration and functional test procedures, have been revised, or will be revised prior to implementation to reflect the new 30-month drift values. The revised setpoint calculations were developed in accordance with the RBS commitment to the guidance provided in Regulatory Guide 1.105, "Instrument Setpoints" (Reference 3) as implemented by the RBS setpoint methodology (Reference 5). These calculations determined the instrument uncertainties, setpoint, and allowable value for the affected function. The allowable values were determined in a manner suitable to establish limits for their application. As such, the allowable values ensure that sufficient margins are maintained in the applicable safety analyses to confirm the affected instruments are capable of performing their intended design function. In performing the revised setpoint calculations described above, the use of ISA RP67.04, Part II (Reference 6), "Method 3" was not utilized.

3.2 Standby Liquid Control System

10 CFR 50.62 requires that each Boiling Water Reactor (BWR) "must have a standby liquid control system (SLCS) with the capability of injecting into the reactor pressure vessel a borated water solution at such a flow rate, level of Boron concentration and Boron-10 isotope enrichment, and accounting for reactor pressure vessel volume, that the resulting reactivity control is at least equivalent to that resulting from injection of 86 gallons per minute of 13 weight percent sodium pentaborate decahydrate solution at the natural Boron-10 isotope abundance into a 251-inch inside diameter reactor pressure vessel for a given core design." Requirements for the SLCS system are included in Technical Specification (TS) 3.1.7, "SLC System." The SLC system must have the capacity for controlling the reactivity difference between the steady-state rated operating conditions of the reactor with voids and the cold shutdown conditions, including shutdown from the most reactive condition at any time in core life.

Requirements for the SLC system are documented in specification GE-22A3130AW, "Standby Liquid Control System." RBS uses sodium pentaborate for SLCS. The sodium pentaborate is enriched with the Boron-10 isotope (80 atom % Boron-10 concentration) to ensure compliance.

Fuel vendor information indicates that the current required reactor vessel Boron weight for cold shutdown may not be adequate for cycles 18 and 19. For cycles 18 and 19, the margin to the USAR requirement for maintaining cold shutdown is small, possibly to the point that it will negatively impact core design and increase fuel costs. As a result, RBS has conservatively opted to increase the required quantity of Boron-10 injected into the vessel to ensure that future core designs are not negatively impacted. Therefore, the weight of the Boron-10 contained in the SLC tank minimum required available solution volume will be increased from 143 lbm to 170 lbm to ensure adequate margin for future core designs.

3.3 Loss of Power Instrumentation

Branch Technical Position (BTP) PSB-1 requires that a second level of undervoltage protection, in addition to loss-of-voltage protection be provided to protect safety related equipment from sustained operation at degraded voltage levels which might affect equipment operability. Accordingly, an analytical limit is established based on the maximum bus voltage recovery time during a LOCA response relative to electrical component (e.g., motors) sequencing and acceleration when loaded on the bus.

Successful operation of the required safety functions of the emergency core cooling systems (ECCS) is dependent upon the availability of adequate power sources for energizing the various components such as pump motors, motor operated valves, and the associated control components. The LOP instrumentation monitors the 4.16 kV emergency buses. Offsite power is the preferred source of power for the 4.16 kV emergency buses. If the monitors determine that insufficient power is available, the buses are disconnected from the offsite power sources and connected to the onsite diesel generator (DG) power sources.

The under-voltage protection scheme at RBS consists of two levels of protection for Class 1E equipment. The first level is set at approximately 70% of nominal bus voltage with a time delay of three seconds. Following this delay the Class 1E distribution system is automatically separated from the offsite power system.

The second level of under-voltage protection is designed to actuate when grid voltages fall below the lowest expected value, which maintains an emergency bus voltage greater than minimum necessary for Class 1E equipment function. Each divisional 4160 V safety related bus has a dedicated circuit consisting of relays arranged in a 2-out-of-3 coincidence logic with two time delays each. The two separate time delays are for low voltage protection during two conditions of operation: with and without a LOCA occurrence. The first time delay is approximately 5 seconds to accommodate normal motor starting transients. Following this delay, an alarm in the main control room alerts the operator to the degraded condition. An occurrence of a LOCA signal subsequent to this degraded voltage condition immediately separates the Class 1E 4160 V safety related bus from the offsite power system. The second time delay is approximately 60 seconds. After this delay, if the operator has failed to restore adequate voltages, the Class 1E 4160 V safety related bus is automatically separated from the offsite power system, irrespective of the occurrence of a LOCA.

The Division 1 4160 V safety-related bus is fed directly from preferred transformer RTX-XSR1C and the Division 2 4160 V safety related bus is fed directly from preferred transformer RTX-XSR1D. A non-safety 4160 V bus is also fed from each of these preferred transformers. In turn, a third non-safety 4160 V bus can be fed from either of the upstream non-safety 4160 V buses.

The results of the drift analysis indicated that the projected 30-month drift values for the instruments Division 1 and 2 - 4.16 kV Emergency Bus Undervoltage – Degraded Voltage - 4.16 kV Basis (Table 3.3.8.1-1, Function 1.c) and Division 3 - 4.16 kV Emergency Bus Undervoltage – Degraded Voltage - 4.16 kV Basis (Table 3.3.8.1-1, Function 2.c) exceeded the drift allowance provided in the setpoint calculation for these functions and were outside the TS Allowable Values (AVs).

The TS Bases criteria for the degraded voltage instrumentation requires that, (1) the degraded voltage AVs to be low enough to prevent inadvertent power supply transfer, but high enough to ensure that sufficient voltage is available to the required equipment, and, (2) the time delay AVs to be long enough to provide time for the offsite power supply to recover to normal voltages, but short enough to ensure that sufficient power is available to the required equipment.

Generic Letter (GL) 89-10 MOVs are required to perform their design basis function at degraded grid voltage concurrent with a LOCA. An existing operability determination, performed and documented in accordance with the RBS corrective action program, addresses a portion of the GL 89-10 population. Because all Class 1E motors were purchased to be capable of starting and accelerating their driven equipment with motor terminal voltages of 70 or 80 percent of motor nameplate voltage without affecting performance or equipment life, no operability concerns exist for any equipment. However, a group of the motor operated valves governed by GL 89-10 was determined to have insufficient voltage to pick up their torque switch, allowing potential failure after reaching their safety position. Thus, although the valves maintain their operability, full functionality is not maintained under current analysis. To bring the valves back to full functionality, RBS will use the results of the offsite grid stability studies to increase the AV and trip setpoints of the Division 1 and 2 -4.16 kV emergency Bus Undervoltage - Degraded Voltage - 4.16 kV Basis (Table 3.3.8.1-1, Function 1.c) and Division 3 - 4.16 kV emergency Bus Undervoltage - Degraded Voltage - 4.16 kV Basis (Table 3.3.8.1-1, Function 2.c)

RBS has completed offsite grid stability studies which indicate grid voltage levels remain above 99.5% per unit. RBS will initiate a change to offsite power requirements to ensure that grid voltage is no lower than 97.5% per unit, up from the current limit of 95% per unit. This change will result in an increase in minimum grid voltage operability limit from 95% per unit to 97.5% per unit and a new MCR alarm set point for Low Grid Voltage of 98.2%, up from 98%.

The purpose of this proposed change is to define new AVs in TS Table 3.3.8.1-1 for Function 1.c and 2.c to address the effect of 30 month drift uncertainty on the degraded voltage setpoints, as well as restoring full function to all GL 89-10 valves. The proposed AV changes have no impact on current Table 3.3.8.1-1 for functions 1.a, 1.b, 1.d, 1.e, 2.a, 2.b, 2.d or 2.e setpoints or trip logic. It is the intent in establishing the new AVs that the current design and licensing basis for the settings as reflected in TS Bases description B.3.3.8.1 not be changed. In maintaining current design and licensing basis, the subject AV changes are being made utilizing current LOCA response voltage analysis, the setpoint methodology consistent with current industry standards, and evaluated 30 month drift uncertainty for the degraded voltage relays.

The AV for Item 1.c will be changed from ≥ 3689 V and ≤ 3735.2 V to ≥ 3760.4 V and ≤ 3795.5 V. The AV for Item 2.c will be changed from ≥ 3674.0 V and ≤ 3721.2 V to ≥ 3754.5 V and ≤ 3792.6 V. Since the current plant setpoints for both of these functions will not be conservative for this change, the new calculated nominal trip setpoints will be revised in the Technical Requirements Manual. RBS proposes to maintain the existing setpoints and AVs until after NRC approval of the license amendment.

Information will be added to the TS Bases consistent the NRC staff's position on complying with 10 CFR 50.36 as provided in RIS 2006-17, and further clarified by Technical Specification Task Force (TSTF)-493, Revision 3, and TSTF-09-07 letter to NRC dated February 23, 2009, for non-safety limit-related limiting safety system setting functions. Specifically, the following information will be added for the Loss of Power degraded volage function:

> "There is a plant-specific program which verifies that this instrument channel functions as required by verifying the As-Left and As-Found settings are consistent with those established by the setpoint methodology."

3.4 Source Term

The core source term was revaluated to support the transition to 24 month fuel cycles. The current source term is based on the CINDER computer code, which was submitted to and approved by the NRC as part of the Alternative Source Term submittal (reference NRC letter approving TS Amendment 132 to RBS Technical Specifications, TAC No. MB5021, dated March 14, 2003). The fuel vendor, Global Nuclear Fuel, no longer supports CINDER. As a result, a methodology change is required which is being addressed via 10CFR50.59. The source term calculations performed in support of implementation of 24 month cycles at RBS were performed using the ORIGN01P computer code. ORIGN01P is the GE-Hitachi production version of the ORIGEN 2.1 computer code, which is recommended by Regulatory Guide 1.183, "Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors," Section 3.1. ORIGN01P has been used by GE-Hitachi for numerous source term calculations previously approved by the NRC.

4.0 TECHNICAL ANALYSIS

4.1 Generic Letter 91-04 Changes

The proposed TS surveillance frequency changes from 18 months to 24 months have been divided into two categories as generally outlined in Reference 1. The categories are: (1) changes to surveillances other than channel calibrations, identified as "Non-Calibration Changes"; and (2) changes involving the channel calibration frequency identified as "Channel Calibration Changes."

4.1.A Non-Calibration Changes

Reference 1 identifies three steps to evaluate non-calibration changes:

<u>STEP 1</u>: Licensees should evaluate the effect on safety of the change in surveillance intervals to accommodate a 24 month fuel cycle. This evaluation should support a conclusion that the effect on safety is small.

EVALUATION

Each non-calibration SR frequency being changed has been evaluated with respect to the effect on plant safety. The methodology utilized to justify the conclusion that extending the testing interval has a minimal effect on safety was based on the fact that the function/feature is:
(1) Tested on a more frequent basis during the operating cycle by other plant programs;
(2) Designed to have redundant counterparts or be single failure proof; or
(3) Highly reliable.

A summary of the evaluation of the effect on safety for each non-calibration SR frequency being changed is presented in Attachment 5.

<u>STEP 2</u>: Licensees should confirm that historical maintenance and surveillance data do not invalidate this conclusion.

EVALUATION

The surveillance test history of the affected SRs has been evaluated. This evaluation consisted of a review of available surveillance test results and associated maintenance records for at least five cycles of operation prior to and including the Spring 2008 refueling outage. With the extension of the testing frequency to 24 months, there will be a longer period between each surveillance performance. If a failure that results in the loss of the associated safety function should occur during the operating cycle, that would only be detected by the performance of the 18-month TS SR, then the increase in the surveillance testing interval might result in a decrease in the associated function's availability. In addition to evaluating these surveillance failures, potential common failures of similar components tested by different surveillances were also evaluated. This additional evaluation determined whether there is evidence of repetitive failures among similar plant components. These common component failures have been further evaluated to determine if there was an impact on plant reliability, the evaluation determined that current plant programs are adequate to ensure system reliability.

The surveillance failures that are detailed in Attachment 5 exclude failures that:
(a) Did not impact a TS safety function or TS operability;
(b) Are detectable by required testing performed more frequently than the 18 month surveillance being extended; or
(c) Where the cause can be attributed to an associated event such as a preventative maintenance task, human error, previous modification, or previously existing design deficiency, or that were subsequently re-performed successfully with no

intervening corrective maintenance (e.g., plant conditions or malfunctioning measurement and test equipment (M&TE) may have caused aborting the test performance).

These categories of failures are not related to potential unavailability due to testing interval extension, and are therefore not listed or further evaluated in this submittal.

This review of surveillance test history validated the conclusion that the impact, if any, on system availability will be minimal as a result of the change to a 24-month testing frequency. Specific SR test failures, and justification for this conclusion, are discussed in Attachment 5.

STEP 3: Licensees should confirm that the performance of surveillances at the bounding surveillance interval limit provided to accommodate a 24-month fuel cycle would not invalidate any assumption in the plant licensing basis.

EVALUATION

As part of the evaluation of each affected SR, the impact of the changes against the assumptions in the RBS licensing basis was reviewed. In general, testing interval changes have no impact on the plant licensing basis. In some cases, the change to a 24-month fuel cycle may require a change to licensing basis information as described in the Updated Safety Analysis Report (USAR). However, since no changes requiring NRC review and approval have been identified, the USAR changes associated with fuel cycle extension to 24 months will be drafted in accordance with RBS procedures that implement 10 CFR 50.59, "Changes, tests and experiments," and will be submitted in accordance with 10 CFR 50.71, "Maintenance of records, making of reports," paragraph (e).

The performance of surveillances extended for a 24 month fuel cycle will be trended as a part of the Maintenance Rule Program. Any degradation in performance will be evaluated to verify that the degradation is not due to the extension of surveillance or maintenance activities.

4.1.B Channel Calibration Changes

Reference 1 identifies seven steps for the evaluation of instrumentation calibration changes.

STEP 1: Confirm that instrument drift as determined by as-found and as-left calibration data from surveillance and maintenance records has not, except on rare occasions, exceeded acceptable limits for a calibration interval.

EVALUATION

The effect of longer calibration intervals on the TS instrumentation was evaluated by performing a review of the surveillance test history for the affected instrumentation including, where appropriate, an instrument drift study. In performing the historical evaluation, an effort was made to retrieve recorded channel calibration data for associated instruments for at least five operating cycles prior to and including the Spring 2008 refueling outage. By obtaining this past recorded calibration data, an acceptable basis for drawing conclusions about the expectation of satisfactory performance can be made.

The failure history evaluation and drift study found that instrument drift has not exceeded the current Technical Specification Allowable Values except for the SR test failures discussed in Attachment 5. The specific evaluation basis supporting this conclusion is also discussed in Attachment 5.

STEP 2: Confirm that the values of drift for each instrument type (make, model, and range) and application have been determined with a high probability and a high degree of confidence. Provide a summary of the methodology and assumptions used to determine the rate of instrument drift with time based upon historical plant calibration data.

EVALUATION

The effect of longer calibration intervals on the TS instrumentation was evaluated by performing an instrument drift study. In performing the drift study, an effort was made to retrieve recorded channel calibration data for associated instruments for at least five operating cycles prior to and including the Spring 2008 refueling outage. By obtaining this past recorded calibration data, a true representation of instrument drift was determined (except in cases where all collected data still resulted in insufficient data for valid statistical analysis).

The methodology used to perform the drift analysis is consistent with the methodology utilized by other utilities requesting transition to a 24-Month fuel cycle. The methodology is also based on Electric Power Research Institute (EPRI) TR-103335, "Statistical Analysis of Instrument Calibration Data" (Reference 7) and is provided as Attachment 6.

STEP 3: Confirm that the magnitude of instrument drift has been determined with a high probability and a high degree of confidence for a bounding calibration interval of 30 months for each instrument type (make, model number, and range) and application that performs a safety function. Provide a list of the channels by TS section that identifies these instrument applications.

EVALUATION

In accordance with the methodology described in the EOI drift design guide, the magnitude of instrument drift has been determined with a high degree of confidence and a high degree of probability (at least 95/95) for a bounding calibration interval of 30 months for each instrument make, model, and range. For instruments not in service long enough to establish a projected drift value or where an insufficient number of calibrations have been performed to utilize the statistical methods (i.e., fewer than 30 calibrations for any given group of instruments), the SR frequency is proposed to be extended to a 24-month interval based on other, more frequent testing or justification obtained from analysis as presented in Attachment 5. The list of affected channels by TS section, including make, model, and range, is provided in Attachment 7.

STEP 4: Confirm that a comparison of the projected instrument drift errors has been made with the values of drift used in the setpoint analysis. If this results in revised setpoints to accommodate larger drift errors, provide proposed TS changes to update trip setpoints. If the drift errors result in revised safety analysis to support existing setpoints, provide a summary of the updated analysis conclusions to confirm that safety limits and safety analysis assumptions are not exceeded.

EVALUATION

The projected drift values were compared to the design allowances as calculated in the associated instrument setpoint analyses. If the projected drift for an instrument fell outside the existing setpoint calculation design allowances, then the analysis of the setpoint, allowable value, and/or analytical limit was reviewed. Setpoint calculations were revised, or will be revised prior to implementation, as necessary, to accommodate appropriate drift values. When the 30-month projected drift value for an instrument could be accommodated within the existing or revised setpoint analysis, the SR frequency was changed to "24 months" with no change to the TS allowable value or licensing basis analytical limit.

As necessary, RBS setpoint calculations, and affected calibration and functional test procedures, have been revised, or will be revised prior to implementation, to reflect the new 30-month drift values. The revised setpoint calculations were developed in accordance with RBS commitment to the guidance provided in RG 1.105 (Reference 3) as implemented by the RBS setpoint methodology (Reference 5), ISA Standard 67.04, 1975 (Reference 6), and IEEE Standard 741-1997, "Criteria for the Protection of Class 1E Power Systems and Equipment in Nuclear Power Generating Stations" (Reference 9). These calculations determined the instrument loop uncertainty, setpoint, and allowable value for the affected function. The allowable values were determined in a manner suitable to establish limits for their application. As such, the revised allowable values ensure that sufficient margins are maintained in the applicable safety analyses to confirm the affected instruments are capable of performing their intended design function.

STEP 5: Confirm that the projected instrument errors caused by drift are acceptable for control of plant parameters to effect a safe shutdown with the associated instrumentation.

EVALUATION

As discussed in the previous sections, the calculated drift values have been compared to drift allowances in the RBS design basis. For instrument loops that provide process variable indication only, an evaluation was performed as discussed in Attachment 5 to verify that the instruments can still be effectively utilized to perform a plant safe shutdown. In no case was a change to the safe shutdown analysis required to support any change to a 24-month frequency.

STEP 6: Confirm that all conditions and assumptions of the setpoint and safety analyses have been checked and are appropriately reflected in the acceptance criteria of plant surveillance procedures for Channel Checks, Channel Functional Tests, and Channel Calibrations.

EVALUATION

Applicable surveillance test procedures are being reviewed and acceptance criteria updated to incorporate the necessary changes resulting from any revision to setpoint calculations. Any necessary changes resulting from the reviews will be incorporated into the instrument surveillance procedures prior to the implementation of the 24 month surveillance test frequency. Existing plant processes ensure that all conditions and assumptions of the setpoint and safety analyses have been checked and are appropriately reflected in the acceptance criteria of plant surveillance procedures for Channel Checks, Channel Functional Tests, and Channel Calibrations.

STEP 7: Provide a summary description of the program for monitoring and assessing the effects of increased calibration surveillance intervals on instrument drift and its effect on safety.

EVALUATION

Instruments with TS calibration surveillance frequencies extended to 24 months will be monitored and trended. As-found and as-left calibration data will be recorded for each 24 month calibration activity for a period of three cycles. This will identify occurrences of instruments found outside of their allowable value and instruments whose performance is not as assumed in the drift or setpoint analysis. When as-found conditions are outside the allowable value, an evaluation will be performed in accordance with the RBS corrective action program to determine if the assumptions made to extend the calibration frequency are still valid and to evaluate the effect on plant safety.

In addition, the trending program will address calibration as-found data found to be outside of the "as-found tolerance" (AFT). This AFT is based on the expected 30-month drift for the instruments. The trending program will require that any time a calibration as-found value is found outside the AFT, the occurrence will be entered into the RBS corrective action program and the instrument performance evaluated to assure that it is still enveloped by the assumptions in the drift or setpoint analysis. This will allow the trending program to evaluate AFAL values to verify that the performance of the instruments is within expected boundaries and that adverse trends are detected and evaluated. This evaluation will be conducted for three (3) 24-month calibration intervals to ensure the assumptions in the setpoint calculations continue to be valid. If this evaluation indicates that instrument performance is not consistent with assumptions, corrective actions will be taken in accordance with station corrective action program requirements.

5.0 REGULATORY ANALYSIS

5.1 NO SIGNIFICANT HAZARDS CONSIDERATION

Entergy has evaluated whether a significant hazards consideration is involved with the proposed amendment by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," discussed below.

The requested change would affect certain Technical Specification (TS) Surveillance Requirement (SR) frequencies that are specified as "18 months" by revising them to "24 months" in accordance with the guidance of Generic Letter (GL) 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24 Month Fuel Cycle," dated April 2, 1991. Also consistent with this guidance, a change is proposed to Administrative Controls Section 5.5.7, "Ventilation Filter Testing Program (VFTP)," to address changes to 18 month frequencies that are specified in Regulatory Guide (RG) 1.52, "Design, Inspection, and Testing Criteria for Air Filtration and Adsorption Units of Post-Accident Engineered-Safety-Feature Atmosphere Cleanup Systems in Light-Water-Cooled Nuclear Power Plants," Revision 2. In order to support some changes to the 18-month frequencies, setpoint analysis revisions result in changes to selected allowable values. For all other allowable value changes, a change to the safety analysis (analytical limit or other design basis assumption) is not required to support the change.

1. Does the proposed amendment involve a significant increase in the probability or consequences of an accident previously evaluated?

   Response: No.

   The proposed TS changes involve a change in the surveillance testing intervals and allowable values to facilitate a change in the operating cycle length. The proposed TS changes do not physically impact the plant. The proposed TS changes do not degrade the performance of, or increase the challenges to, any safety systems assumed to function in the accident analysis. The proposed TS changes do not impact the usefulness of the SRs in evaluating the operability of required systems and components, or the way in which the surveillances are performed. In addition, the frequency of surveillance testing is not considered an initiator of any analyzed accident, nor does a revision to the frequency introduce any accident initiators. The specific value of the allowable value is not considered an initiator of any analyzed accident. Therefore, the proposed change does not involve a significant increase in the probability of an accident previously evaluated.

   The consequences of a previously evaluated accident are not significantly increased. The proposed change does not affect the performance of any equipment credited to mitigate the radiological consequences of an accident. Evaluation of the proposed TS changes demonstrated that the availability of credited equipment is not significantly affected because of other more frequent testing that is performed, the availability of redundant systems and equipment, and the high reliability of the equipment. Historical review of surveillance test results and associated maintenance records did not find evidence of failures that would invalidate the above conclusions.

The allowable values have been developed in accordance with RG 1.105, "Instrument Setpoints," to ensure that the design and safety analysis limits are satisfied. The methodology used for the development of the allowable values ensures the affected instrumentation remains capable of mitigating design basis events as described in the safety analyses and that the results and radiological consequences described in the safety analyses remain bounding. Therefore, the proposed change does not alter the ability to detect and mitigate events and, as such, does not involve a significant increase in the consequences of an accident previously evaluated.

Standby Liquid Control System

The proposed change in required weight of Boron-10 in SLC does not physically impact the plant, nor does it degrade the performance of, or increase the challenges to, any safety systems assumed to function in the accident analysis. The consequences of a previously evaluated accident are not increased. The proposed change does not affect the performance of any equipment credited to mitigate the radiological consequences of an accident. Evaluation of the proposed TS changes demonstrated that the availability of credited equipment is not affected. Therefore, the proposed change does not alter the ability to detect and mitigate events and, as such, does not involve a significant increase in the consequences of an accident previously evaluated.

Loss of Power Instrumentation

A change to the Allowable Values (AVs) is proposed for Table 3.3.8.1-1, Item 1.c and Item 2.c. The proposed change is the result of application of the RBS Instrument Setpoint Methodology using plant-specific drift values and incorporating margins available based on a revised off-site reliability study. Application of this methodology results in AVs that more accurately reflect total device accuracy, as well as that of test equipment and calculated drift between surveillances. The proposed change will not result in any hardware changes. The instrumentation is not assumed to be an initiator of any analyzed event. Existing operating margin between plant conditions and actual plant setpoints is not significantly reduced due to the proposed changes. The role of the instrumentation is in mitigating and thereby, limiting the consequences of accidents.

The AVs were developed to ensure the design and safety analysis limits are satisfied. The methodology used for the development of the AVs ensures that: (1) the affected instrumentation remains capable of mitigating design basis events as described in the safety analysis, and, (2) the results and radiological consequences described in the safety analysis remain bounding. Additionally, the proposed change does not alter the plant's ability to detect and mitigate events. Therefore, this change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

The change in the degraded voltage protection voltage AVs allows the protection scheme to function as originally designed. The proposed allowable values ensure that the Class 1E distribution system remains connected to the offsite power system when adequate offsite voltage is available and motor starting transients are considered.

Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the proposed amendment create the possibility of a new or different kind of accident from any accident previously evaluated?

Response: No.

The proposed TS changes involve a change in the surveillance testing intervals and allowable values to facilitate a change in the operating cycle length. The proposed TS changes do not introduce any failure mechanisms of a different type than those previously evaluated, since there are no physical changes being made to the facility. No new or different equipment is being installed. No installed equipment is being operated in a different manner. As a result, no new failure modes are being introduced. The way surveillance tests are performed remains unchanged. A historical review of surveillance test results and associated maintenance records indicated there was no evidence of any failures that would invalidate the above conclusions.

Therefore, the proposed change does not create the possibility of a new or different kind of accident from any previously evaluated.

Standby Liquid Control System

The proposed change to the required weight of Boron-10 in SLC does not introduce any failure mechanisms of a different type than those previously evaluated, since there are no physical changes being made to the facility. No new or different equipment is being installed. No installed equipment is being operated in a different manner. As a result, no new failure modes are being introduced. The way surveillance tests are performed remains unchanged. A historical review of surveillance test results and associated maintenance records indicated there was no evidence of any failures that would invalidate the above conclusions.

Loss of Power Instrumentation

The proposed change in AVs is the result of application of the Instrument Setpoint Methodology using plant-specific drift values and does not create the possibility of a new or different kind of accident from any accident previously evaluated. This is based upon the fact that the method and manner of plant operation are unchanged.

The use of the proposed AVs does not impact safe operation of the plant in that the safety analysis limits are maintained. The proposed change in AVs involves no system additions. The AVs are revised to ensure the affected instrumentation remains capable of mitigating accidents and transients. Plant equipment will not be operated in a manner different from previous operation, except that setpoints may be changed. No additional failure mechanisms are introduced as a result of the changes to the allowable values. Since operational methods remain unchanged and the operating parameters were evaluated to maintain the plant within existing design basis criteria, no different type of failure or accident is created

Therefore, the proposed change does not create the possibility of a new or different kind of accident from any previously evaluated.

3. Does the proposed amendment involve a significant reduction in a margin of safety?

Response: No.

The proposed TS changes involve a change in the surveillance testing intervals and allowable values to facilitate a change in the operating cycle length. The impact of these changes on system availability is not significant, based on other more frequent testing that is performed, the existence of redundant systems and equipment, and overall system reliability. Evaluations have shown there is no evidence of time dependent failures that would impact the availability of the systems. The proposed changes do not significantly impact the condition or performance of structures, systems, and components relied upon for accident mitigation. The proposed changes in TS instrumentation allowable values are the result of application of the RBS setpoint methodology using plant specific drift values. The revised allowable values more accurately reflect total instrumentation loop accuracy including drift while continuing to protect any assumed analytical limit. The proposed changes do not result in any hardware changes or in any changes to the analytical limits assumed in accident analyses. Existing operating margin between plant conditions and actual plant setpoints is not significantly reduced due to these changes. The proposed changes do not significantly impact any safety analysis assumptions or results.

Standby Liquid Control System

The proposed change in required weight of Boron-10 in SLC is to facilitate a change in the operating cycle length. The proposed change does not result in any hardware changes or in any changes to the analytical limits assumed in accident analyses. Existing operating margin between plant conditions and actual plant setpoints is not reduced due to this change. The proposed change does not impact any safety analysis assumptions or results. Therefore, the proposed change does not involve a significant reduction in a margin of safety.

Loss of Power Instrumentation

The proposed protection voltage AVs are low enough to prevent inadvertent power supply transfer, but high enough to ensure that sufficient voltage is available to the required equipment. The proposed change does not involve a reduction in a margin of safety. The proposed change was developed using a methodology to ensure safety analysis limits are not exceeded. As such, this proposed change does not involve a significant reduction in a margin of safety.

Therefore, the proposed change does not involve a significant reduction in a margin of safety.

Based on the above, Entergy concludes that the proposed amendment present no significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and accordingly, a finding of "no significant hazards consideration" is justified.

5.2 APPLICABLE REGULATORY REQUIREMENTS / CRITERIA

Regulatory requirement 10 CFR 50.36, "Technical specifications," provides the content required in a licensee's TS. Specifically, 10 CFR 50.36(c)(3) requires that the TS include surveillance requirements. The proposed SR frequency changes continue to support the requirements of 10 CFR 50.36(c)(3) to assure that the necessary quality of systems and components is maintained, that facility operation will be within safety limits, and that the limiting conditions for operation are met.

NRC GL 91-04 provides generic guidance for evaluating a 24 month surveillance test interval for TS SRs. This request for license amendment provides the RBS specific evaluation of each step outlined by the NRC in GL 91-04 and provides a description of the methodology used by RBS to complete the evaluation for each specific TS SR being revised.

The proposed allowable value changes have been evaluated to determine whether applicable regulations and requirements continue to be met. New allowable values have been calculated in accordance with the guidance provided in RG 1.105, "Instrument Setpoints," as implemented by the RBS setpoint methodology, and the Instrument Society of America (ISA) Standard 67.04, 1994. These calculations determine the instrument uncertainties, setpoints, and allowable values for the affected functions. The allowable values have been determined in a manner suitable to establish limits for their application. As such, the revised allowable values ensure that sufficient margins are maintained in the applicable safety analyses to confirm the affected instruments are capable of performing their intended design function. In performing the revised setpoint calculations to support any revised allowable values described above, ISA RP67.04, Part II, "Method 3" was not utilized. Entergy has determined that the proposed changes do not require any exemptions or relief from regulatory requirements, other than the TS, and do not affect conformance with any General Design Criteria differently than described in the RBS USAR.

In conclusion, based on the considerations discussed above, (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

6.0 ENVIRONMENTAL CONSIDERATION

A review has determined that the proposed amendment would change a requirement with respect to installation or use of a facility component located within the restricted area, as defined in 10 CFR 20, or would change an inspection or surveillance requirement. However, the proposed amendment does not involve (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amounts of any effluent that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed amendment meets the eligibility criterion for categorical exclusion set forth in 10 CFR 51.22(c)(9). Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the proposed amendment.

7.0 REFERENCES

(1) NRC Generic Letter 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24-Month Fuel Cycle," dated April 2, 1991

(2) Regulatory Guide 1.52, "Design, Inspection, and Testing Criteria for Air Filtration and Adsorption Units of Post-Accident Engineered-Safety-Feature Atmosphere Cleanup Systems in Light-Water-Cooled Nuclear Power Plants," Revision 2, dated March 1978

(3) Regulatory Guide 1.105, "Instrument Setpoints," Revision 1, dated November 1976

(4) Regulatory Guide 1.197, "Demonstrating Control Room Envelope Integrity at Nuclear Power Reactors," Revision 0, May 2003

(5) EN-IC-S-007-R Rev. 0 "Instrument Loop Uncertainty & Setpoint Calculations"

(6) Instrument Society of America (ISA) S67.04, "Setpoints for Nuclear Safety-Related Instrumentation," Part I, and ISA RP67.04, "Methodologies for the Determination of Setpoints for Nuclear Safety-Related Instrumentation," Part II, 1994

(7) EPRI TR-103335, "Statistical Analysis of Instrument Calibration Data," Revision 1, dated October 1998

(8) NRC Status Report on the Staff review of EPRI Technical Report (TR)-103335, Revision 0, Status Report, dated December 1, 1997

(9) IEEE Standard 741-1997, "Criteria for the Protection of Class 1E Power Systems and Equipment in Nuclear Power Generating Stations"

Attachment 2
RBG-46932

Markup of Proposed Technical Specification Page Changes

List of affected Technical Specifications pages:

3.1-22
3.1-25

3.3-5
3.3-6
3.3-13
3.3-17
3.3-21
3.3-24
3.3-27
3.3-28
3.3-31
3.3-38
3.3-46
3.3-52
3.3-60
3.3-64
3.3-67
3.3-70
3.3-73
3.3-74
3.3-77

3.4-6
3.4-7
3.4-11
3.4-19

3.5-5
3.5-9
3.5-11
3.5-12

3.6-8
3.6-17
3.6-18
3.6-24
3.6-26
3.6-30
3.6-42
3.6-43
3.6-45
3.6-47
3.6-50
3.6-52
3.6-59
3.6-60
3.6-66
3.6-70

3.7-4
3.7-7
3.7-11
3.7-14

3.8-7
3.8-8
3.8-9
3.8-10
3.8-11
3.8-12
3.8-13
3.8-14
3.8-25
3.8-26

5.0-11
5.0-16a

SURVEILLANCE REQUIREMENTS (continued)

170

SURVEILLANCE		FREQUENCY
SR 3.1.7.5	Verify the available weight of Boron-10 is ≥ ~~143~~ lbs, and the percent weight concentration of sodium pentaborate in solution is ≤ 9.5% by weight, and determine the minimum required available solution volume.	31 days <u>AND</u> Once within 24 hours after water or boron is added to solution <u>AND</u> Once within 24 hours after solution temperature is restored to ≥ 45°F
SR 3.1.7.6	Verify each SLC subsystem manual, power operated, and automatic valve in the flow path that is not locked, sealed, or otherwise secured in position, is in the correct position, or can be aligned to the correct position.	31 days
SR 3.1.7.7	Verify each pump develops a flow rate ≥ 41.2 gpm at a discharge pressure ≥ 1250 psig.	In accordance with the Inservice Testing Program
SR 3.1.7.8	Verify flow through one SLC subsystem from pump into reactor pressure vessel.	~~18~~ months on a STAGGERED TEST BASIS

24

(continued)

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.1.8.1	------------------------------NOTE------------------------------ Not required to be met on vent and drain valves closed during performance of SR 3.1.8.2. -- Verify each SDV vent and drain valve is open.	31 days
SR 3.1.8.2	Cycle each SDV vent and drain valve to the fully closed and fully open position.	92 days
SR 3.1.8.3	Verify each SDV vent and drain valve: a. Closes in ≤ 30 seconds after receipt of an actual or simulated scram signal; and b. Opens when the actual or simulated scram signal is reset.	~~18~~ months 24

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.10	Calibrate the trip units.	92 days
SR 3.3.1.1.11	-----NOTES----- 1. Neutron detectors and flow reference transmitters are excluded. 2. For Function 2.a, not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. 3. For Function 2.b. the digital components of the flow control trip reference cards are excluded. ---------- Perform CHANNEL CALIBRATION.	184 days
SR 3.3.1.1.12	Perform CHANNEL FUNCTIONAL TEST.	~~18~~ 24 months
SR 3.3.1.1.13	-----NOTES----- 1. Neutron detectors are excluded. 2. For IRMs, not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. ---------- Perform CHANNEL CALIBRATION.	~~18~~ 24 months
SR 3.3.1.1.14	Verify the APRM Flow Biased Simulated Thermal Power–High time constant is within the limits specified in the COLR.	~~18~~ 24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.1.1.15	Perform LOGIC SYSTEM FUNCTIONAL TEST.	2 ~~18~~ months
SR 3.3.1.1.16	Verify Turbine Stop Valve Closure and Turbine Control Valve Fast Closure Trip Oil Pressure–Low Functions are not bypassed when THERMAL POWER is ≥ 40% RTP.	2 ~~18~~ months 24
SR 3.3.1.1.17	Calibrate the flow reference transmitters.	2 ~~18~~ months
SR 3.3.1.1.18	---NOTES--- 1. Neutron detectors are excluded. 2. For Functions 3, 4, and 5 in Table 3.3.1.1-1, the channel sensors are excluded. 3. For Function 6, "n" equals 4 channels for the purpose of determining the STAGGERED TEST BASIS Frequency. --- Verify the RPS RESPONSE TIME is within limits.	2 ~~18~~ months on a STAGGERED TEST BASIS

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.1.2.4	---NOTE--- Not required to be met with less than or equal to four fuel assemblies adjacent to the SRM and no other fuel assemblies in the associated core quadrant. --- Verify count rate is: a. ≥ 3.0 cps, or b. ≥ 0.7 cps with a signal to noise ratio ≥ 2:1.	12 hours during CORE ALTERATIONS <u>AND</u> 24 hours
SR 3.3.1.2.5	---NOTE--- Not required to be performed until 12 hours after IRMs on Range 2 or below. --- Perform CHANNEL FUNCTIONAL TEST.	31 days
SR 3.3.1.2.6	---NOTES--- 1. Neutron detectors are excluded. 2. Not required to be performed until 12 hours after IRMs on Range 2 or below. --- Perform CHANNEL CALIBRATION.	24 2 ~~18~~ months

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.2.1.4	-----------------------------NOTE----------------------------- Not required to be performed until 1 hour after THERMAL POWER is ≤ 10% RTP in MODE 1. --- Perform CHANNEL FUNCTIONAL TEST.	92 days
SR 3.3.2.1.5	Calibrate the low power setpoint trip units. The Allowable Value shall be > 10% RTP and ≤ 35% RTP.	92 days
SR 3.3.2.1.6	Verify the RWL high power Function is not bypassed when THERMAL POWER is > 68.2% RTP.	92 days
SR 3.3.2.1.7	Perform CHANNEL CALIBRATION.	184 days
SR 3.3.2.1.8	-----------------------------NOTE----------------------------- Not required to be performed until 1 hour after reactor mode switch is in the shutdown position. --- Perform CHANNEL FUNCTIONAL TEST.	24 4 2 ~~18~~ months
SR 3.3.2.1.9	Verify the bypassing and movement of control rods required to be bypassed in Rod Action Control System (RACS) is in conformance with applicable analyses by a second licensed operator or other qualified member of the technical staff.	Prior to and during the movement of control rods bypassed in RACS

SURVEILLANCE REQUIREMENTS

-----NOTE-----
These SRs apply to each Function in Table 3.3.3.1-1.

	SURVEILLANCE	FREQUENCY
SR 3.3.3.1.1	Perform CHANNEL CHECK.	31 days
SR 3.3.3.1.2	Deleted	
SR 3.3.3.1.3	Perform CHANNEL CALIBRATION.	~~18~~ 2 months

24

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.3.2.2	Verify each required control circuit and transfer switch is capable of performing the intended functions.	2 ~~18~~ months 24
SR 3.3.3.2.3	Perform CHANNEL CALIBRATION for each required instrumentation channel, except valve position instrumentation.	2 ~~18~~ months

SURVEILLANCE REQUIREMENTS

---NOTE---
When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours, provided the associated Function maintains EOC-RPT trip capability.

	SURVEILLANCE	FREQUENCY
SR 3.3.4.1.1	Perform CHANNEL FUNCTIONAL TEST.	92 days
SR 3.3.4.1.2	Calibrate the trip units.	92 days
SR 3.3.4.1.3	Perform CHANNEL CALIBRATION. The Allowable Values shall be: a. TSV Closure: ≤ 7% closed. b. TCV Fast Closure, Trip Oil Pressure — Low: ≥ 465 psig.	~~18~~ months 24
SR 3.3.4.1.4	Perform LOGIC SYSTEM FUNCTIONAL TEST, including breaker actuation.	~~18~~ months
SR 3.3.4.1.5	Verify TSV Closure and TCV Fast Closure, Trip Oil Pressure — Low Functions are not bypassed when THERMAL POWER is ≥ 40% RTP.	~~18~~ months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.4.1.6	----------NOTE---------- Breaker interruption time may be assumed from the most recent performance of SR 3.3.4.1.7. ------------------------ Verify the EOC-RPT SYSTEM RESPONSE TIME is within limits.	24 ~~18~~ months on a STAGGERED TEST BASIS
SR 3.3.4.1.7	Determine RPT breaker interruption time.	60 months

	SURVEILLANCE	FREQUENCY
SR 3.3.4.2.2	Perform CHANNEL FUNCTIONAL TEST.	92 days
SR 3.3.4.2.3	Calibrate the trip units.	92 days
SR 3.3.4.2.4	Perform CHANNEL CALIBRATION. The Allowable Values shall be: a. Reactor Vessel Water Level–Low Low, Level 2: ≥ -47 inches; and b. Reactor Steam Dome Pressure–High: ≤ 1165 psig.	~~18~~ months 24
SR 3.3.4.2.5	Perform LOGIC SYSTEM FUNCTIONAL TEST, including breaker actuation.	~~18~~ months

SURVEILLANCE REQUIREMENTS

---NOTES---

1. Refer to Table 3.3.5.1-1 to determine which SRs apply for each ECCS Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed as follows: (a) for up to 6 hours for Functions 3.c, 3.f, 3.g, and 3.h; and (b) for up to 6 hours for Functions other than 3.c, 3.f, 3.g, and 3.h, provided the associated Function or the redundant Function maintains ECCS initiation capability.

SURVEILLANCE		FREQUENCY
SR 3.3.5.1.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.5.1.2	Perform CHANNEL FUNCTIONAL TEST.	92 days
SR 3.3.5.1.3	Calibrate the trip unit.	92 days
SR 3.3.5.1.4	Perform CHANNEL CALIBRATION.	92 days
SR 3.3.5.1.5	Perform CHANNEL CALIBRATION.	~~18~~ 2 months 24
SR 3.3.5.1.6	Perform LOGIC SYSTEM FUNCTIONAL TEST.	~~18~~ 2 months

SURVEILLANCE REQUIREMENTS

-----NOTES-----

1. Refer to Table 3.3.5.2-1 to determine which SRs apply for each RCIC Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed as follows: (a) for up to 6 hours for Functions 2 and 5; and (b) for up to 6 hours for Functions 1, 3, and 4 provided the associated Function maintains RCIC initiation capability.

SURVEILLANCE		FREQUENCY
SR 3.3.5.2.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.5.2.2	Perform CHANNEL FUNCTIONAL TEST.	92 days
SR 3.3.5.2.3	Calibrate the trip units.	92 days
SR 3.3.5.2.4	Perform CHANNEL CALIBRATION.	~~18~~ months 24
SR 3.3.5.2.5	Perform LOGIC SYSTEM FUNCTIONAL TEST.	~~18~~ months

SURVEILLANCE REQUIREMENTS

---NOTES---

1. Refer to Table 3.3.6.1-1 to determine which SRs apply for each Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours, provided the associated Function maintains isolation capability.

	SURVEILLANCE	FREQUENCY
SR 3.3.6.1.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.6.1.2	Perform CHANNEL FUNCTIONAL TEST.	92 days
SR 3.3.6.1.3	Calibrate the trip unit.	92 days
SR 3.3.6.1.4	Perform CHANNEL CALIBRATION.	92 days
SR 3.3.6.1.5	Perform CHANNEL CALIBRATION.	~~18~~ months
SR 3.3.6.1.6	Perform LOGIC SYSTEM FUNCTIONAL TEST.	~~18~~ months 24
SR 3.3.6.1.7	---------------------------NOTE--------------------------- Channel sensors are excluded. --- Verify the ISOLATION SYSTEM RESPONSE TIME for the Main Steam Isolation Valves is within limits.	~~18~~ months on a STAGGERED TEST BASIS

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.6.2.3	Calibrate the trip unit.	92 days
SR 3.3.6.2.4	Perform CHANNEL CALIBRATION.	~~18~~ months 24
SR 3.3.6.2.5	Perform LOGIC SYSTEM FUNCTIONAL TEST.	~~18~~ months

SURVEILLANCE REQUIREMENTS

---NOTES---

1. Refer to Table 3.3.6.3-1 to determine which SRs apply for each Containment Unit Cooler System Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours, provided the associated Function maintains containment unit cooler initiation capability.

SURVEILLANCE		FREQUENCY
SR 3.3.6.3.1	Perform CHANNEL CHECK.	24 hours
SR 3.3.6.3.2	Perform CHANNEL FUNCTIONAL TEST.	92 days
SR 3.3.6.3.3	Calibrate the trip unit.	92 days
SR 3.3.6.3.4	Perform CHANNEL CALIBRATION.	~~18~~ 2 months 24
SR 3.3.6.3.5	Perform LOGIC SYSTEM FUNCTIONAL TEST.	~~18~~ 2 months

SURVEILLANCE REQUIREMENTS

-----NOTE-----
When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours, provided the associated Function maintains LLS or relief initiation capability, as applicable.

	SURVEILLANCE	FREQUENCY
SR 3.3.6.4.1	Perform CHANNEL FUNCTIONAL TEST.	92 days
SR 3.3.6.4.2	Calibrate the trip unit.	92 days
SR 3.3.6.4.3	Perform CHANNEL CALIBRATION. The Allowable Values shall be: a. Relief Function Low: 1133 ± 15 psig Medium: 1143 ± 15 psig High: 1153 ± 15 psig b. LLS Function Low open: 1063 ± 15 psig close: 956 ± 15 psig Medium open: 1103 ± 15 psig close: 966 ± 15 psig High open: 1143 ± 15 psig close: 976 ± 15 psig	~~18~~ 24 months
SR 3.3.6.4.4	Perform LOGIC SYSTEM FUNCTIONAL TEST.	~~18~~ months

SURVEILLANCE REQUIREMENTS

--NOTES--

1. Refer to Table 3.3.7.1-1 to determine which SRs apply for each Function.
2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains CRFA initiation capability.

	SURVEILLANCE	FREQUENCY
SR 3.3.7.1.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.7.1.2	Perform CHANNEL FUNCTIONAL TEST.	92 days
SR 3.3.7.1.3	Calibrate the trip units.	92 days
SR 3.3.7.1.4	Perform CHANNEL CALIBRATION.	~~18~~ 2 months
SR 3.3.7.1.5	Perform LOGIC SYSTEM FUNCTIONAL TEST.	~~18~~ 2 months

24

SURVEILLANCE REQUIREMENTS

-----NOTES-----

1. Refer to Table 3.3.8.1-1 to determine which SRs apply for each LOP Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 2 hours provided the associated Function maintains DG initiation capability.

SURVEILLANCE		FREQUENCY
SR 3.3.8.1.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.8.1.2	Perform CHANNEL FUNCTIONAL TEST.	31 days
SR 3.3.8.1.3	Perform CHANNEL CALIBRATION.	~~18~~ months
SR 3.3.8.1.4	Perform LOGIC SYSTEM FUNCTIONAL TEST.	~~18~~ months

24

Table 3.3.8.1-1 (page 1 of 1)
Loss of Power Instrumentation

FUNCTION	REQUIRED CHANNELS PER DIVISION	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Divisions 1 and 2 - 4.16 kV Emergency Bus Undervoltage			
a. Loss of Voltage - 4.16 kV basis	3	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 2850 V and ≤ 3090 V
b. Loss of Voltage - Time Delay	1	SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 2.67 seconds and ≤ 3.33 seconds
c. Degraded Voltage - 4.16 kV basis	3	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4	≥ ~~3689.0~~ 3760.4 V and ≤ ~~3785.2~~ 3795.5 V
d. Degraded Voltage - Time Delay, No LOCA	1	SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 53.4 seconds and ≤ 66.6 seconds
e. Degraded Voltage - Time Delay, LOCA	1	SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 4.5 seconds and ≤ 5.7 seconds
2. Division 3 - 4.16 kV Emergency Bus Undervoltage			
a. Loss of Voltage - 4.16 kV basis	2	SR 3.3.8.1.1 SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 2831 V and ≤ 3259 V
b. Loss of Voltage - Time Delay	2	SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 2.67 seconds and ≤ 3.33 seconds
c. Degraded Voltage - 4.16 kV basis	2	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4	≥ ~~3674.0~~ 3754.5 V and ≤ ~~3721.2~~ 3792.6 V
d. Degraded Voltage - Time Delay, No LOCA	2	SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 53.4 seconds and ≤ 66.6 seconds
e. Degraded Voltage - Time Delay, LOCA	2	SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 4.5 seconds and ≤ 5.7 seconds

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.8.2.2	Perform CHANNEL CALIBRATION. The Allowable Values shall be: a. Overvoltage Bus A ≤ 132 V Bus B ≤ 132 V b. Undervoltage Bus A ≥ 115 V Bus B ≥ 115 V c. Underfrequency (with time delay set to ≤ 4.0 seconds.) Bus A ≥ 57 Hz Bus B ≥ 57 Hz	~~18~~ months 24
SR 3.3.8.2.3	Perform a system functional test.	~~18~~ months

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.2 Flow Control Valves (FCVs)

LCO 3.4.2 A recirculation loop FCV shall be OPERABLE in each operating recirculation loop.

APPLICABILITY: MODES 1 and 2.

ACTIONS

---NOTE---
Separate Condition entry is allowed for each FCV.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or two required FCVs inoperable.	A.1 Lock up the FCV.	4 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.2.1	Verify each FCV fails "as is" on loss of hydraulic pressure at the hydraulic unit.	2 ~~18~~ months 24

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.2.2	Verify average rate of each FCV movement is: a. ≤ 11% of stroke per second for opening; and b. ≤ 11% of stroke per second for closing.	~~18~~ 24 months

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.4.4.2	------------------------------NOTE------------------------------ Valve actuation may be excluded. -- Verify each required relief function S/RV actuates on an actual or simulated automatic initiation signal.	24 ~~18~~ months
SR 3.4.4.3	------------------------------NOTE------------------------------ Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. -- Verify each required S/RV relief mode actuator strokes when manually actuated.	In accordance with the Inservice Testing Program on a STAGGERED TEST BASIS for each valve solenoid

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.4.7.1	Perform CHANNEL CHECK of required drywell atmospheric monitoring system.	12 hours
SR 3.4.7.2	Perform CHANNEL FUNCTIONAL TEST of required leakage detection instrumentation.	31 days
SR 3.4.7.3	Perform CHANNEL CALIBRATION of required leakage detection instrumentation.	~~18~~ 24 months 24

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.5.1.5	---------------------------NOTE--------------------------- Vessel injection/spray may be excluded. -- Verify each ECCS injection/spray subsystem actuates on an actual or simulated automatic initiation signal.	24 ~~18~~ months
SR 3.5.1.6	---------------------------NOTE--------------------------- Valve actuation may be excluded. -- Verify the ADS actuates on an actual or simulated automatic initiation signal.	24 ~~18~~ months
SR 3.5.1.7	---------------------------NOTE--------------------------- Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. -- Verify each ADS valve relief mode actuator strokes when manually actuated.	In accordance with the Inservice Testing Program on a STAGGERED TEST BASIS for each valve solenoid
SR 3.5.1.8	---------------------------NOTE--------------------------- ECCS actuation instrumentation is excluded. -- Verify the ECCS RESPONSE TIME for each ECCS injection/spray subsystem is within limits.	24 ~~18~~ months

SURVEILLANCE REQUIREMENTS (continued)

<table>
<tr><th colspan="2">SURVEILLANCE</th><th>FREQUENCY</th></tr>
<tr><td>SR 3.5.2.5</td><td>Verify each required ECCS pump develops the specified flow rate with the specified pump differential pressure.

SYSTEM | FLOW RATE | PUMP DIFFERENTIAL PRESSURE
LPCS | ≥ 5010 gpm | ≥ 282 psid
LPCI | ≥ 5050 gpm | ≥ 102 psid
HPCS | ≥ 5010 gpm | ≥ 415 psid</td><td>In accordance with the Inservice Testing Program</td></tr>
<tr><td>SR 3.5.2.6</td><td>-----NOTE-----
Vessel injection/spray may be excluded.

Verify each required ECCS injection/spray subsystem actuates on an actual or simulated automatic initiation signal.</td><td>24
~~18~~ months</td></tr>
</table>

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.5.3.1	Verify the RCIC System piping is filled with water from the pump discharge valve to the injection valve.	31 days
SR 3.5.3.2	Verify each RCIC System manual, power operated, and automatic valve in the flow path, that is not locked, sealed, or otherwise secured in position, is in the correct position.	31 days
SR 3.5.3.3	---------------------------NOTE--------------------------- Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. -- Verify, with RCIC steam supply pressure ≤ 1075 psig and ≥ 920 psig, the RCIC pump can develop a flow rate ≥ 600 gpm against a system head corresponding to reactor pressure.	92 days
SR 3.5.3.4	---------------------------NOTE--------------------------- Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. -- Verify, with RCIC steam supply pressure ≤ 165 psig and ≥ 150 psig, the RCIC pump can develop a flow rate ≥ 600 gpm against a system head corresponding to reactor pressure.	24 ~~18~~ months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.5.3.5	-----NOTE----- Vessel injection may be excluded. -----	
	Verify the RCIC System actuates on an actual or simulated automatic initiation signal.	24 ~~18~~ months

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.1.2.4	Verify, from an initial pressure of 90 psig, the primary containment air lock seal pneumatic system pressure does not decay at a rate equivalent to > 1.50 psig for a period of 24 hours.	~~18~~ months 24

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.6.1.3.4	Verify the isolation time of each power operated and each automatic PCIV, except MSIVs, is within limits.	In accordance with the Inservice Testing Program
SR 3.6.1.3.5	---NOTE--- Only required to be met in MODES 1, 2, and 3. --- Perform leakage rate testing for each primary containment purge valve with resilient seals.	In accordance with the Primary Containment Leakage Rate Testing Program
SR 3.6.1.3.6	Verify the isolation time of each MSIV is ≥ 3 seconds and ≤ 5 seconds.	In accordance with the Inservice Testing Program
SR 3.6.1.3.7	Verify each automatic PCIV actuates to the isolation position on an actual or simulated isolation signal.	~~18~~ 24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.1.3.8	Verify in-leakage rate of ≤ 340 scfh for each of the following valve groups when tested at 11.5 psid for MS-PLCS valves. a. Division I MS-PLCS valves b. Division II MS-PLCS valves	~~18~~ months 24
SR 3.6.1.3.9	-------------------------------NOTE------------------------------- Only required to be met in MODES 1, 2, and 3. -- Verify the combined leakage rate for all secondary containment bypass leakage paths is ≤ 580,000 cc/hr when pressurized to ≥ P_a.	In accordance with the Primary Containment Leakage Rate Testing Program

(continued)

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.6.1.6.1	-------------------------NOTE-------------------------- Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. --- Verify each LLS valve relief mode actuator strokes when manually actuated.	In accordance with the Inservice Testing Program on a STAGGERED TEST BASIS for each valve solenoid
SR 3.6.1.6.2	-------------------------NOTE-------------------------- Valve actuation may be excluded. --- Verify the LLS System actuates on an actual or simulated automatic initiation signal.	24 ~~18~~ months

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.7.1	Verify each required primary containment unit cooler pressure relief and backdraft damper in the flow path that is not locked, sealed, or otherwise secured in position, is in the correct position.	31 days
SR 3.6.1.7.2	Verify each required primary containment unit cooler develops a flow rate of ≥ 50,000 cfm on recirculation flow through the unit cooler.	92 days
SR 3.6.1.7.3	Verify each required primary containment unit cooler actuates throughout its emergency operating sequence on an actual or simulated automatic initiation signal.	~~18~~ months 24

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.6.1.9.2	Operate each PVLCS compressor ≥ 15 minutes.	31 days
SR 3.6.1.9.3	Perform a system functional test of each MS-PLCS subsystem.	~~18~~ 24 months

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 3.	12 hours

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.6.3.2.1	Energize each primary containment and drywell hydrogen igniter division and perform current versus voltage measurements to verify required igniters in service.	184 days
SR 3.6.3.2.2	---NOTE--- Not required to be performed until 92 days after discovery of four or more igniters in the division inoperable. --- Energize each primary containment and drywell hydrogen igniter division and perform current versus voltage measurements to verify required igniters in service.	92 days
SR 3.6.3.2.3	Verify each required igniter in inaccessible areas develops sufficient current draw for a ≥ 1700°F surface temperature.	~~18~~ 24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued

SURVEILLANCE		FREQUENCY
SR 3.6.3.2.4	Verify each required igniter in accessible areas develops a surface temperature of ≥ 1700°F.	~~18~~ months 24

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 3.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.3.3.1	Operate each primary containment/drywell hydrogen mixing subsystem for ≥ 15 minutes.	Every COLD SHUTDOWN, if not performed within the previous 92 days.
SR 3.6.3.3.2	Verify each primary containment/drywell hydrogen mixing subsystem flow rate is ≥ 600 cfm.	~~18~~ 24 months

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.6.4.1.2	Verify all secondary containment equipment hatches are closed and sealed and loop seals filled.	31 days
SR 3.6.4.1.3	Verify each secondary containment access door is closed, except when the access opening is being used for entry and exit.	31 days 24
SR 3.6.4.1.4	Verify each standby gas treatment (SGT) subsystem will draw down the shield building annulus and auxiliary building to ≥ 0.5 and ≥ 0.25 inch of vacuum water gauge in ≤ 18.5 and ≤ 34.5 seconds, respectively.	~~18~~ 2 months on a STAGGERED TEST BASIS
SR 3.6.4.1.5	Deleted 24	Not Applicable
SR 3.6.4.1.6	Verify each SGT subsystem can maintain ≥ 0.5 and ≥ 0.25 inch of vacuum water gauge in the shield building annulus and auxiliary building, respectively, for 1 hour.	~~18~~ 2 months on a STAGGERED TEST BASIS
SR 3.6.4.1.7	Deleted	Not Applicable

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.4.2.1	Verify the isolation time of each required power operated automatic SCID and FBID is within limits.	92 days
SR 3.6.4.2.2	Verify each required automatic SCID and FBID actuates to the isolation position on an actual or simulated automatic isolation signal.	~~18~~ 24 months

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.6.4.3.1	Operate each SGT subsystem for ≥ 10 continuous hours with heaters operating.	31 days
SR 3.6.4.3.2	Perform required SGT filter testing in accordance with the Ventilation Filter Testing Program (VFTP).	In accordance with the VFTP
SR 3.6.4.3.3	Verify each SGT subsystem actuates on an actual or simulated initiation signal.	~~18~~ 24 months
SR 3.6.4.3.4	Verify each SGT filter cooling bypass damper can be opened and the fan started.	~~18~~ 24 months

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.4.7.1	Verify one fuel building ventilation charcoal filtration subsystem in operation.	12 hours
SR 3.6.4.7.2	Operate each fuel building ventilation charcoal filtration subsystem for ≥ 10 continuous hours with heaters operating.	31 days
SR 3.6.4.7.3	Perform fuel building ventilation charcoal filtration filter testing in accordance with the Ventilation Filter Testing Program (VFTP).	In accordance with the VFTP
SR 3.6.4.7.4	Verify each fuel building ventilation charcoal filtration subsystem actuates on an actual or simulated initiation signal.	~~18~~ months 24
SR 3.6.4.7.5	Verify each fuel building ventilation charcoal filtration filter cooling bypass damper can be opened and the fan started.	~~18~~ months

3.6 CONTAINMENT SYSTEMS

3.6.5.1 Drywell

LCO 3.6.5.1 The drywell shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Drywell inoperable.	A.1	Restore drywell to OPERABLE status.	1 hour
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 3.	12 hours
	<u>AND</u>		
	B.2	Be in MODE 4.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.5.1.1	Verify personnel door inflatable seal air flask pressure ≥ 75 psig.	7 days
SR 3.6.5.1.2	Verify from an initial pressure of 75 psig, the personnel door inflatable seal pneumatic system pressure does not decay at a rate equivalent to ≥ 20.0 psig for a period of 24 hours.	~~18~~ months 24

(continued)

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.6.5.2.1	Deleted	
SR 3.6.5.2.2	Verify drywell air lock seal air flask pressure is ≥ 75 psig.	7 days
SR 3.6.5.2.3	-----NOTE----- Only required to be performed upon entry into drywell. ----- Verify only one door in the drywell air lock can be opened at a time.	24 months
SR 3.6.5.2.4	Deleted	
SR 3.6.5.2.5	Verify, from an initial pressure of 75 psig, the drywell air lock seal pneumatic system pressure does not decay at a rate equivalent to > 20.0 psig for a period of 24 hours.	~~18~~ 24 months

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.5.3.4	Verify the isolation time of each power operated and each automatic drywell isolation valve is within limits.	In accordance with the Inservice Testing Program
SR 3.6.5.3.5	Verify each automatic drywell isolation valve actuates to the isolation position on an actual or simulated isolation signal.	~~18~~ 24 months
SR 3.6.5.3.6	Verify the cumulative time that the primary containment/drywell hydrogen mixing inlet or outlet penetrations are open to be ≤ 5 hours per 365 days in Modes 1 and 2, and ≤ 90 hours per 365 days in Mode 3.	31 days

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.7.1.4	Verify each required SSW subsystem manual, power operated, and automatic valve in the flow path servicing safety related systems or components, that is not locked, sealed, or otherwise secured in position, is in the correct position.	31 days
SR 3.7.1.5	Verify each SSW subsystem actuates on an actual or simulated initiation signal.	24 ~~18~~ months

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. Two CRFA subsystems inoperable during movement of recently irradiated fuel assemblies in the primary containment or fuel building, or during OPDRVs. OR One or more CRFA subsystems inoperable due to inoperable CRE boundary during movement of recently irradiated fuel assemblies in the primary containment or fuel building during OPDRVs.	F.1 Suspend movement of recently irradiated fuel assemblies in the primary containment and fuel building. AND F.2 Initiate action to suspend OPDRVs.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.7.2.1	Operate each CRFA subsystem for $\geq$ 10 continuous hours with the heaters operating.	31 days
SR 3.7.2.2	Perform required CRFA filter testing in accordance with the Ventilation Filter Testing Program (VFTP).	In accordance with the VFTP
SR 3.7.2.3	Verify each CRFA subsystem actuates on an actual or simulated initiation signal.	~~18~~ months 24

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. Required Action and associated Completion Time of Condition B not met during movement of recently irradiated fuel assemblies in the primary containment or fuel building, or during OPDRVs.	E.1 Suspend movement of recently irradiated fuel assemblies in the primary containment and fuel building. AND E.2 Initiate action to suspend OPDRVs.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.3.1	Verify each control room AC subsystem has the capability to remove the assumed heat load.	~~18~~ months 24

3.7 PLANT SYSTEMS

3.7.5 Main Turbine Bypass System

LCO 3.7.5 The Main Turbine Bypass System shall be OPERABLE.

APPLICABILITY: THERMAL POWER ≥ 23.8 RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Main Turbine Bypass System inoperable.	A.1 Restore Main Turbine Bypass System to OPERABLE status.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < 23.8% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.5.1	Verify one complete cycle of each main turbine bypass valve.	31 days
SR 3.7.5.2	Perform a system functional test.	~~18~~ 24 months
SR 3.7.5.3	Verify the TURBINE BYPASS SYSTEM RESPONSE TIME is within limits.	~~18~~ 24 months

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.1.7	------------------------------NOTE------------------------------ All DG starts may be preceded by an engine prelube period. -- Verify each DG starts from standby conditions and achieves: a. For DG 1A and DG 1B, steady state voltage ≥ 3740 V and ≤ 4580 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz, in ≤ 10 seconds. b. For DG 1C: 1. Maximum of 5400 V, and 66.75 Hz, and 2. Steady state voltage ≥ 3740 V and ≤ 4580 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz, in ≤ 13 seconds.	184 days
SR 3.8.1.8	------------------------------NOTE------------------------------ This Surveillance shall not be performed in MODE 1 or 2. However, credit may be taken for unplanned events that satisfy this SR. -- Verify manual transfer of unit power supply from the normal offsite circuit to required alternate offsite circuit.	24 ~~18~~ months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.9	-----------------------------NOTE----------------------------- 1. Credit may be taken for unplanned events that satisfy this SR. 2. If performed with DG synchronized with offsite power, it shall be performed at a power factor ≤ 0.9 -- Verify each DG rejects a load greater than or equal to its associated single largest post accident load and following load rejection, the engine speed is maintained less than nominal plus 75% of the difference between nominal speed and the overspeed trip setpoint or 15% above nominal, whichever is lower.	24 ~~18~~ months
SR 3.8.1.10	-----------------------------NOTE----------------------------- Credit may be taken for unplanned events that satisfy this SR. -- Verify each DG operating at a power factor ≤ 0.9 does not trip and voltage is maintained ≤ 4784 V for DG 1A and DG 1B and ≤ 5400 V for DG 1C during and following a load rejection of a load ≥ 3030 kW and ≤ 3130 kW for DGs 1A and 1B and ≥ 2500 kW and ≤ 2600 kW for DG 1C.	24 ~~18~~ months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.1.11	-----NOTES----- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not be performed in MODE 1, 2, or 3. (Not applicable to DG 1C) However, credit may be taken for unplanned events that satisfy this SR. ---------- Verify on an actual or simulated loss of offsite power signal: a. De-energization of emergency buses; b. Load shedding from emergency buses for Divisions I and II; and c. DG auto-starts from standby condition and: 1. energizes permanently connected loads in ≤ 10 seconds for DG 1A and DG 1B and ≤ 13 seconds for DG 1C, 2. energizes auto-connected shutdown loads, 3. maintains steady state voltage ≥ 3740 V and ≤ 4580 V, 4. maintains steady state frequency ≥ 58.8 Hz and ≤ 61.2 Hz, and 5. supplies permanently connected and auto-connected shutdown loads for ≥ 5 minutes.	24 2 ~~18~~ months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.12	------------------------------NOTES------------------------------ 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not be performed in MODE 1 or 2. (Not applicable to DG 1C) However, credit may be taken for unplanned events that satisfy this SR. --- Verify on an actual or simulated Emergency Core Cooling System (ECCS) initiation signal each DG auto-starts from standby condition and: a. For DG 1C during the auto-start maintains voltage ≤ 5400 V and frequency ≤ 66.75 Hz; b. In ≤ 10 seconds for DG 1A and DG 1B and ≤ 13 seconds for DG 1C after auto-start and during tests, achieves voltage ≥ 3740 V and ≤ 4580 V; c. In ≤ 10 seconds for DG 1A and DG 1B and ≤ 13 seconds for DG 1C after auto-start and during tests, achieves frequency ≥ 58.8 Hz and ≤ 61.2 Hz; and d. Operates for ≥ 5 minutes.	24 ~~18~~ months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.1.13	-------------------------NOTE------------------------- This Surveillance shall not be performed in MODE 1, 2, or 3. (Not applicable to DG 1C) However, credit may be taken for unplanned events that satisfy this SR. --- Verify each DG's automatic trips are bypassed on an actual or simulated ECCS initiation signal except: a. Engine overspeed; and b. Generator differential current.	2 ~~18~~ months 24
SR 3.8.1.14	-------------------------NOTES------------------------- 1. Momentary transients outside the load and power factor ranges do not invalidate this test. 2. Credit may be taken for unplanned events that satisfy this SR. --- Verify each DG operating at a power factor ≤ 0.9, operates for ≥ 24 hours: a. For DG 1A and DG 1B loaded ≥ 3030 kW and ≤ 3130 kW; and b. For DG 1C: 1. For ≥ 2 hours loaded ≥ 2750 kW and ≤ 2850 kW, and 2. For the remaining hours of the test loaded ≥ 2500 kW and ≤ 2600 kW.	2 ~~18~~ months 24

(continued)

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.1.15	----------NOTES---------- 1. This Surveillance shall be performed within 5 minutes of shutting down the DG after the DG has operated ≥ 1 hour loaded ≥ 3000 kW and ≤ 3100 kW for DG 1A and DG 1B, and ≥ 2500 kW and ≤ 2600 for DG 1C, or operating temperatures have stabilized, which ever is longer. Momentary transients outside of the load range do not invalidate this test. 2. All DG starts may be preceded by an engine prelube period. -------------------- Verify each DG starts and achieves, in ≤ 10 seconds for DG 1A and DG 1B and ≤ 13 seconds for DG 1C, voltage ≥ 3740 V and ≤ 4580 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	24 2 ~~18~~ months
SR 3.8.1.16	----------NOTE---------- This Surveillance shall not be performed in MODE 1, 2, or 3. (Not applicable to DG 1C) However, credit may be taken for unplanned events that satisfy this SR. -------------------- Verify each DG: a. Synchronizes with offsite power source while loaded with emergency loads upon a simulated restoration of offsite power; b. Transfers loads to offsite power source; and c. Returns to ready-to-load operation.	24 2 ~~18~~ months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.1.17	------------------------------NOTE------------------------------ This Surveillance shall not be performed in MODE 1, 2, or 3. (Not applicable to DG 1C) However, credit may be taken for unplanned events that satisfy this SR. --- Verify, with a DG operating in test mode and connected to its bus, an actual or simulated ECCS initiation signal overrides the test mode by: a. Returning DG to ready-to-load operation; and b. Automatically energizing the emergency loads from offsite power.	~~18~~ months 24
SR 3.8.1.18	------------------------------NOTE------------------------------ This Surveillance shall not be performed in MODE 1, 2, or 3. (Not applicable to DG 1C) However, credit may be taken for unplanned events that satisfy this SR. --- Verify sequence time is within ± 10% of design for each load sequencer timer.	24 ~~18~~ months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.19	-------------------------------NOTES------------------------------ 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not be performed in MODE 1, 2, or 3. (Not applicable to DG 1C) However, credit may be taken for unplanned events that satisfy this SR. ---	
	Verify, on an actual or simulated loss of offsite power signal in conjunction with an actual or simulated ECCS initiation signal: a. De-energization of emergency buses; b. Load shedding from emergency buses for Divisions I and II; and c. DG auto-starts from standby condition and: 1. energizes permanently connected loads in ≤ 10 seconds for DG 1A and DG 1B and ≤ 13 seconds for DG 1C, 2. energizes auto-connected emergency loads, 3. achieves steady state voltage ≥ 3740 V and ≤ 4580 V, 4. achieves steady state frequency ≥ 58.8 Hz and ≤ 61.2 Hz, and 5. supplies permanently connected and auto-connected emergency loads for ≥ 5 minutes.	~~18~~ 24 months

(continued)

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.8.4.1	Verify battery terminal voltage is ≥ 130.2 V on float charge.	7 days
SR 3.8.4.2	Verify no visible corrosion at battery terminals and connectors. <u>OR</u> Verify battery connection resistance is ≤ 1.5 E-4 ohm for inter-cell connections, ≤ 1.5 E-4 ohm for inter-rack connections, ≤ 1.5 E-4 ohm for inter-tier connections, and ≤ 1.5 E-4 ohm for terminal connections.	92 days
SR 3.8.4.3	Verify battery cells, cell plates, and racks show no visual indication of physical damage or abnormal deterioration.	~~18~~ months
SR 3.8.4.4	Remove visible corrosion, and verify battery cell to cell and terminal connections are coated with anti-corrosion material.	~~18~~ months 24
SR 3.8.4.5	Verify battery connection resistance is ≤ 1.5 E-4 ohm for inter-cell connections, ≤ 1.5 E-4 ohm for inter-rack connections, ≤ 1.5 E-4 ohm for inter-tier connections, and ≤ 1.5 E-4 ohm for terminal connections.	~~18~~ months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.4.6	Verify each battery charger supplies ≥ 300 amps for chargers 1A and 1B and ≥ 50 amps for charger 1C at ≥ 130.2 V for ≥ 8 hours.	~~18~~ months 24
SR 3.8.4.7	------------------------------NOTES------------------------------ 1. SR 3.8.4.8 may be performed in lieu of SR 3.8.4.7 once per 60 months. 2. This Surveillance shall not be performed in MODE 1, 2, or 3 (not applicable to Division III). However, credit may be taken for unplanned events that satisfy this SR. -- Verify battery capacity is adequate to supply, and maintain in OPERABLE status, the required emergency loads for the design duty cycle when subjected to a battery service test.	~~18~~ months

(continued)

5.5 Programs and Manuals

ASME Boiler and Pressure Vessel Code and applicable Addenda terminology for inservice testing activities	Required frequencies for performing inservice testing activities
Weekly	At least once per 7 days
Monthly	At least once per 31 days
Quarterly or every 3 months	At least once per 92 days
Semiannually or every 6 months	At least once per 184 days
Every 9 months	At least once per 276 days
Yearly or annually	At least once per 366 days
Biennially or every 2 years	At least once per 731 days

b. The provisions of SR 3.0.2 are applicable to the above required frequencies for performing inservice testing activities;

c. The provisions of SR 3.0.3 are applicable to inservice testing activities; and

d. Nothing in the ASME Boiler and pressure Vessel Code shall be construed to supersede the requirements of any TS.

5.5.7 Ventilation Filter Testing Program (VFTP)

A program shall be established to implement the following required testing of Engineered Safety Feature (ESF) filter ventilation systems at the frequencies specified in Regulatory Guide 1.52, Revision 2,

a. Demonstrate for each of the ESF systems that an inplace test of the high efficiency particulate air (HEPA) filters shows a penetration and system bypass < 0.05% when tested in accordance with Regulatory Guide 1.52, Revision 2, and ANSI N510-1989 at the system flowrate specified below ± 10%:

ESF Ventilation System	Flowrate
SGTS	12,500 cfm
FBVS	10,000 cfm
CRFAS	4,000 cfm

except that testing specified at a frequency of 18 months is required at a frequency of 24 months.

(continued)

5.5 Programs and Manuals

5.5.14 Control Room Envelope Habitability Program (continued)

OPERABLE Control Room Fresh Air (CRFA) System, CRE occupants can control the reactor safely under normal conditions and maintain it in a safe condition following a radiological event, hazardous chemical release, or a smoke challenge. The program shall ensure that adequate radiation protection is provided to permit access and occupancy of the CRE under design basis accident (DBA) conditions without personnel receiving radiation exposures in excess of 5 rem total effective dose equivalent (TEDE) for the duration of the accident. The program shall include the following elements:

a. The definition of the CRE and the CRE boundary.

b. Requirements for maintaining the CRE boundary in its design condition including configuration control and preventive maintenance.

c. Requirements for (i) determining the unfiltered air inleakage past the CRE boundary into the CRE in accordance with the testing methods and at the Frequencies specified in Sections C.1 and C.2 of Regulatory Guide 1.197, "Demonstrating Control Room Envelope Integrity at Nuclear Power Reactors," Revision 0, May 2003, and, (ii) assessing CRE habitability at the Frequencies specified in Sections C.1 and C.2 of Regulatory Guide 1.197, Revision 0, except that testing specified at a frequency of 18 months is required at a frequency of 24 months.

d. Measurement, at designated locations, of the CRE pressure relative to all external areas adjacent to the CRE boundary during the pressurization mode of operation by one subsystem of the CRFA System, operating at the flow rate required by the VFTP, at a Frequency of ~~18~~ months on a STAGGERED TEST BASIS. The results shall be trended and used as part of the ~~18~~ month assessment of the CRE boundary. 24

e. The quantitative limits on unfiltered air inleakage into the CRE. These limits shall be stated in a manner to allow direct comparison to the unfiltered air inleakage measured by the testing described in paragraph c. The unfiltered air inleakage limit for radiological challenges is the inleakage flow rate assumed in the licensing basis analyses of DBA consequences. Unfiltered air inleakage limits for hazardous chemicals must ensure that exposure of CRE occupants to these hazards will be within the assumptions in the licensing basis.

f. The provisions of SR 3.0.2 are applicable to the Frequencies for assessing CRE habitability, determining CRE unfiltered inleakage, and measuring CRE pressure and assessing the CRE boundary as required by paragraphs c and d, respectively.

Attachment 3
RBG-46932

Markup of Proposed Technical Specification Bases Pages
(For information only)

List of affected Technical Specification Bases pages:

B 3.1-37
B 3.1-38
B 3.1-43
B 3.1-44
B 3.1-49

B 3.3-28
B 3.3-29
B 3.3-30
B 3.3-31
B 3.3-39
B 3.3-47
B 3.3-59
B 3.3-64
B 3.3-73
B 3.3-74
B 3.3-84
B 3.3-120
B 3.3-133
B 3.3-167
B 3.3-168
B 3.3-180
B 3.3-190
B 3.3-196
B 3.3-207
B 3.3-215
B 3.3-221
B 3.3-222

B 3.4-11
B 3.4-12
B 3.4-20
B 3.4-37

B 3.5-11
B 3.5-12
B 3.5-13a
B 3.5-24
B 3.5-25

B 3.6-26
B 3.6-42
B 3.6-49
B 3.6-76
B 3.6-77
B 3.6-82
B 3.6-94
B 3.6-99
B 3.6-100
B 3.6-115
B 3.6-116
B 3.6-135

B 3.7-8
B 3.7-15
B 3.7-21
B 3.7-27
B 3.7-28

B 3.8-8
B 3.8-18
B 3.8-19
B 3.8-20
B 3.8-21
B 3.8-23
B 3.8-24
B 3.8-25
B 3.8-26
B 3.8-27
B 3.8-28
B 3.8-29
B 3.8-30
B 3.8-55
B 3.8-56

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.7 Standby Liquid Control (SLC) System

BASES

BACKGROUND

The SLC System is designed to provide the capability of bringing the reactor, at any time in a fuel cycle, from full power and minimum control rod inventory (which is at the peak of the xenon transient) to a subcritical condition with the reactor in the most reactive xenon free state without taking credit for control rod movement. The SLC System satisfies the requirements of 10 CFR 50.62 (Ref. 1) on anticipated transient without scram (ATWS).

The SLC System consists of a Boron-10 (B-10) solution storage tank, two positive displacement pumps, two explosive valves, which are provided in parallel for redundancy, and associated piping and valves used to transfer borated water from the storage tank to the reactor pressure vessel (RPV). The borated solution is discharged through the SLC sparger near the bottom of the core shroud.

APPLICABLE SAFETY ANALYSES

The SLC System is manually initiated from the main control room, as directed by the emergency operating procedures, if the operator believes the reactor cannot be shut down, or kept shut down, with the control rods. The SLC System is used in the event that not enough control rods can be inserted to accomplish shutdown and cooldown in the normal manner. The SLC System injects borated water into the reactor core to compensate for all of the various reactivity effects that could occur during plant operation. To meet this objective, it is necessary to inject a quantity of B-10 that produces a concentration of at least 122 ppm of B-10 in the reactor core at 68°F. To allow for potential leakage and imperfect mixing in the reactor system, an additional amount of B-10 equal to 25% of the amount cited above is added (Ref. 2). The concentration limits are calculated such that the required concentration is achieved accounting for dilution in the RPV with normal water level and including the water volume in the residual heat removal shutdown cooling piping and in the recirculation loop piping. This quantity of B-10 in solution (~~143~~ pounds) is

(continued)

170

BASES

APPLICABLE SAFETY ANALYSES (continued)

the amount that is above the pump suction shutoff level in the B-10 solution storage tank. No credit is taken for the portion of the tank volume that cannot be injected.

The SLC System satisfies the requirements of the NRC Policy Statement because operating experience and probabilistic risk assessment have generally shown it to be important to public health and safety.

LCO

The OPERABILITY of the SLC System provides backup capability for reactivity control, independent of normal reactivity control provisions provided by the control rods. The OPERABILITY of the SLC System is based on the conditions of the borated solution in the storage tank and the availability of a flow path to the RPV, including the OPERABILITY of the pumps and valves. Two SLC subsystems are required to be OPERABLE, each containing an OPERABLE pump, an explosive valve and associated piping, valves, and instruments and controls to ensure an OPERABLE flow path.

APPLICABILITY

In MODES 1 and 2, shutdown capability is required. In MODES 3 and 4, control rods are not able to be withdrawn since the reactor mode switch is in Shutdown and a control rod block is applied. This provides adequate controls to ensure the reactor remains subcritical. In MODE 5, only a single control rod can be withdrawn from a core cell containing fuel assemblies. Demonstration of adequate SDM (LCO 3.1.1, "SHUTDOWN MARGIN (SDM)") ensures that the reactor will not become critical. Therefore, the SLC System is not required to be OPERABLE during these conditions, when only a single control rod can be withdrawn.

ACTIONS

A.1

If the product of concentration times enrichment ((C)(E)) of the sodium pentaborate solution is less than the required limits for ATWS mitigation, 170
and otherwise satisfying the required limits on weight (≥ ~~143~~ lbs), concentration (≤ 9.5%), temperature (≥ 45°F), and volume, the remaining capability of the SLC System is sufficient to meet the original licensing basis. In this condition, the concentration must be restored to within limits in 72 hours. It is not necessary under these conditions to enter

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.7.7

Demonstrating each SLC System pump develops a flow rate ≥ 41.2 gpm at a discharge pressure ≥ 1250 psig ensures that pump performance has not degraded during the fuel cycle. This minimum pump flow rate requirement ensures that, when combined with the sodium pentaborate solution concentration requirements, the rate of negative reactivity insertion from the SLC System will adequately compensate for the positive reactivity effects encountered during power reduction, cooldown of the moderator, and xenon decay. This test confirms one point on the pump design curve, and is indicative of overall performance. Such inservice inspections confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. The Frequency of this Surveillance is in accordance with the Inservice Testing Program.

SR 3.1.7.8

48

24

This Surveillance ensures that there is a functioning flow path from the boron solution storage tank to the RPV, including the firing of an explosive valve. The replacement charge for the explosive valve shall be from the same manufactured batch as the one fired or from another batch that has been certified by having one of that batch successfully fired. Other administrative controls, such as those that limit the shelf life of the explosive charges, must be followed. The pump and explosive valve tested should be alternated such that both complete flow paths are tested every ~~36~~ months, at alternating ~~18~~ month intervals. The Surveillance may be performed in separate steps to prevent injecting boron into the RPV. An acceptable method for verifying flow from the pump to the RPV is to pump demineralized water from a test tank through one SLC subsystem and into the RPV. In order to pump this water, the test valve 1C41*F031 is open. A system initiation signal (which normally signals the 1C41*F001 storage tank suction valve) is generated with the test valve open and verification is made that the storage tank suction valve remains closed. The ~~18~~ month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.7.8 (continued)

components usually pass the Surveillance test when performed at the 24 ~~18~~ month Frequency; therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.1.7.9

Enriched sodium pentaborate solution is made by mixing granular, enriched sodium pentaborate with water. Isotopic tests on the sodium pentaborate solution to determine the actual B-10 enrichment must be performed once within 24 hours after boron is added to the solution in order to ensure that the B-10 enrichment is adequate. Enrichment testing is only required when boron addition is made since enrichment change cannot occur by any other process.

REFERENCES

1. 10 CFR 50.62.
2. USAR, Section 9.3.5.3.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.8.3 (continued)

reset signal, the opening of the SDV vent and drain valves is verified. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.1.1 and the scram time testing of control rods in LCO 3.1.3, "Control Rod OPERABILITY," overlap this Surveillance to provide complete testing of the assumed safety function. ~~The 18~~ month Frequency is based on the need to ~~perform this~~ Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the ~~18~~ month Frequency; therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

24

REFERENCES

1. USAR, Section 4.6.1.1.2.4.2.5.

2. 10 CFR 50.67.

3. NUREG-0803, "Generic Safety Evaluation Report Regarding Integrity of BWR Scram System Piping," August 1981.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.9 and SR 3.3.1.1.12

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology. The 92 day Frequency of SR 3.3.1.1.9 is based on the reliability analysis of Reference 9.

For Functions 9 and 10 the CHANNEL FUNCTIONAL TEST shall include the turbine first stage pressure instruments.

24

The ~~18~~ month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the ~~18~~ month Frequency.

SR 3.3.1.1.10

The calibration of trip units provides a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be less conservative than the Allowable Value specified in Table 3.3.1.1-1. If the trip setting is discovered to be less conservative than accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, the channel performance is still within the requirements of the plant safety analysis. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than accounted for in the appropriate setpoint methodology.

For Functions 9 and 10 all applicable trip unit setpoints must be calibrated including the turbine first stage pressure instrument trip unit setpoints.

The Frequency of 92 days for SR 3.3.1.1.10 is based on the reliability analysis of Reference 9.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.11, SR 3.3.1.1.13, and SR 3.3.1.1.17

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

For Functions 9 and 10 the CHANNEL CALIBRATION shall include the turbine first stage pressure instruments.

Note 1 states that neutron detectors and flow reference transmitters are excluded from CHANNEL CALIBRATION because of the difficulty of simulating a meaningful signal. Changes in neutron detector sensitivity are compensated for by performing the 7 day calorimetric calibration (SR 3.3.1.1.2) and the 2000 MWD/T LPRM calibration against the TIPs (SR 3.3.1.1.8). Calibration of the flow reference transmitters is performed 24 ~~on an 18~~ month Frequency (SR 3.3.1.1.17). A second Note is provided that requires the APRM and IRM SRs to be performed within 12 hours of entering MODE 2 from MODE 1. Testing of the MODE 2 APRM and IRM Functions cannot be performed in MODE 1 without utilizing jumpers, lifted leads or movable links. This Note allows entry into MODE 2 from MODE 1 if the associated Frequency is not met per SR 3.0.2. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR. The Frequency of SR 3.3.1.1.11, SR 3.3.1.1.13, and SR 3.3.1.1.17 is based upon the assumption of the magnitude of equipment drift in the setpoint analysis.

Note 3 states that the digital components of the flow control trip reference card are excluded from CHANNEL CALIBRATION of Function 2.b, Average Power Range Monitor Flow Biased Simulated Thermal Power-High. The analog output potentiometers of the flow control trip reference card are not excluded. The flow control trip reference card has an automatic self-test feature which periodically tests the hardware which performs the digital algorithm. Exclusion of the digital components of the flow control trip reference card from CHANNEL CALIBRATION of Function 2.b is based on the conditions required to perform the test and the likelihood of a change in the status of these components not being detected.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.14

The Average Power Range Monitor Flow Biased Simulated Thermal Power-High Function uses an electronic filter circuit to generate a signal proportional to the core THERMAL POWER from the APRM neutron flux signal. This filter circuit is representative of the fuel heat transfer dynamics that produce the relationship between the neutron flux and the core THERMAL POWER. The filter time constant is specified in the COLR and must be verified to ensure that the channel is accurately reflecting the desired parameter. The Frequency of ~~18~~ months is based on engineering judgment and reliability of the components. 24

SR 3.3.1.1.15

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The functional testing of control rods, in LCO 3.1.3, "Control Rod OPERABILITY," and SDV vent and drain valves, in LCO 3.1.8, "Scram Discharge Volume (SDV) Vent and Drain Valves," overlaps this Surveillance to provide complete testing of the assumed safety function.

24 The ~~18~~ month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the ~~18~~ month Frequency.

SR 3.3.1.1.16

This SR ensures that scrams initiated from the Turbine Stop Valve Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure-Low Functions will not be inadvertently bypassed when THERMAL POWER is $\geq$ 40% RTP. This involves calibration of the bypass channels. Adequate margins for the instrument setpoint methodology are incorporated into the actual setpoint. Because main turbine bypass flow can affect this setpoint nonconservatively (THERMAL POWER is derived from turbine first stage pressure), the main turbine bypass valves must remain closed at THERMAL POWER $\geq$ 40% RTP to ensure that the calibration remains valid.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.16 (continued)

If any bypass channel setpoint is nonconservative (i.e., the Functions are bypassed at ≥ 40% RTP, either due to open main turbine bypass valve(s) or other reasons), then the affected Turbine Stop Valve Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure-Low Functions are considered inoperable. Alternatively, the bypass channel can be placed in the conservative condition (nonbypass). If placed in the nonbypass condition, this SR is met and the channel is considered OPERABLE.

The Frequency of ~~18~~ 2 months is based on engineering judgment and reliability of the components. 24

SR 3.3.1.1.18

This SR ensures that the individual channel response times are less than or equal to the maximum values assumed in the accident analysis. The RPS RESPONSE TIME acceptance criteria are included in Reference 10.

As noted, neutron detectors are excluded from RPS RESPONSE TIME testing because the principles of detector operation virtually ensure an instantaneous response time.

RPS RESPONSE TIME tests are conducted ~~on an 18~~ 2 month STAGGERED TEST BASIS. ~~Note 2~~ requires STAGGERED TEST BASIS Frequency ~~to be determ~~ined based on 4 channels per trip system, in lieu ~~of the 8~~ channels specified in Table 3.3.1.1-1 for the MSIV Closure Function. This Frequency is based on the logic interrelationships of the various channels required to produce an RPS scram signal. Therefore, staggered testing results in response time verification of these devices every ~~18~~ 2 months. This Frequency is consistent with the typical industry refueling cycle and is based upon plant operating experience, which shows that random failures of instrumentation components causing serious time degradation, but not channel failure, are infrequent. 24

REFERENCES

1. USAR, Figure 7.2-1.
2. USAR, Section 5.2.2.
3. USAR, Section 6.3.3.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.2.5 (continued)

inability to perform the Surveillance while at higher power levels. Although the Surveillance could be performed while on IRM Range 3, the plant would not be expected to maintain steady state operation at this power level. In this event, the 12 hour Frequency is reasonable, based on the SRMs being otherwise verified to be OPERABLE (i.e., satisfactorily performing the CHANNEL CHECK) and the time required to perform the Surveillances.

SR 3.3.1.2.6

Performance of a CHANNEL CALIBRATION verifies the performance of the SRM detectors and associated circuitry. The Frequency considers the plant conditions required to perform the test, the ease of performing the test, and the likelihood of a change in the system or component status. The neutron detectors are excluded from the CHANNEL CALIBRATION because they cannot readily be adjusted. The detectors are fission chambers that are designed to have a relatively constant sensitivity over the range, and with an accuracy specified for a fixed useful life.

The Note to the Surveillance allows the Surveillance to be delayed until entry into the specified condition of the Applicability. The SR must be performed in MODE 2 within 12 hours of entering MODE 2 with IRMs on Range 2 or below. The allowance to enter the Applicability with the 24 ~~18~~ month Frequency not met is reasonable, based on the limited time of 12 hours allowed after entering the Applicability and the inability to perform the Surveillance while at higher power levels. Although the Surveillance could be performed while on IRM Range 3, the plant would not be expected to maintain steady state operation at this power level. In this event, the 12 hour Frequency is reasonable, based on the SRMs being otherwise verified to be OPERABLE (i.e., satisfactorily performing the CHANNEL CHECK) and the time required to perform the Surveillances.

REFERENCES

None.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.1.6 (continued)

in the nonbypassed condition, the SR is met and the RWL would not be considered inoperable. Because main turbine bypass steam flow can affect the HPSP nonconservatively for the RWL, the RWL is considered inoperable with any main turbine bypass valve open. The Frequency of 92 days is based on the setpoint methodology utilized for these channels.

SR 3.3.2.1.7

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies that the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

The Frequency is based upon the assumption of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.2.1.8

The CHANNEL FUNCTIONAL TEST for the Reactor Mode Switch-Shutdown Position Function is performed by attempting to withdraw any control rod with the reactor mode switch in the shutdown position and verifying a control rod block occurs.

As noted in the SR, the Surveillance is not required to be performed until 1 hour after the reactor mode switch is in the shutdown position, since testing of this interlock with the reactor mode switch in any other position cannot be performed without using jumpers, lifted leads, or movable limits. This allows entry into MODES 3 and 4 if the ~~18~~ month Frequency is not met per SR 3.0.2.

24

The ~~18~~ month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the ~~18~~ month Frequency.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.3.1.1 (continued)

The Frequency of 31 days is based upon plant operating experience with regard to channel OPERABILITY and drift, which demonstrates that failure of more than one channel of a given function in any 31 day interval is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of those displays associated with the required channels of this LCO.

SR 3.3.3.1.2 and SR 3.3.3.1.3

24

For all Functions except the containment and drywell hydrogen analyzers, a CHANNEL CALIBRATION is performed every ~~18~~ months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop including the sensor. The test verifies that the channel responds to the measured parameter with the necessary range and accuracy. The Frequency is based on operating experience and consistency with the typical industry refueling cycles.

For the containment and drywell hydrogen analyzers, the CHANNEL CALIBRATION is performed every 92 days. This Frequency is based on operating experience.

REFERENCES

1. Regulatory Guide 1.97, "Instrumentation for Light-Water Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident," Revision 2, December 1980.

2. NRC Safety Evaluation Report, "Conformance to Regulatory Guide 1.97, Revision 2, River Bend Station, Unit 1," dated June 30, 1986.

3. USAR Section 7.5.

4. Technical Requirements Manual

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.3.2.2

SR 3.3.3.2.2 verifies each required Remote Shutdown System transfer switch and control circuit performs the intended function. This verification is performed from the remote shutdown panel and locally, as appropriate. Operation of the equipment from the remote shutdown panel is not necessary. The surveillance can be satisfied by performance of a continuity check. This will ensure that if the control room becomes inaccessible, the plant can be placed and maintained in MODE 3 from the remote shutdown panel and the local control stations. However, this Surveillance is not required to be performed only during a plant outage. Operating experience demonstrates that Remote Shutdown System control channels usually pass the Surveillance when performed at the ~~18~~ 24 month Frequency.

SR 3.3.3.2.3

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. The test verifies the channel responds to measured parameter values with the necessary range and accuracy. Valve position Functions are excluded since channel performance is adequately determined during performance of other valve surveillances.

The ~~18~~ 24 month Frequency is based upon operating experience and is consistent with the typical industry refueling cycle.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 19.
2. RBS Technical Requirements Manual.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.4.1.4

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The system functional test of the pump breakers is included as a part of this test, overlapping the LOGIC SYSTEM FUNCTIONAL TEST, to provide complete testing of the associated safety function. Therefore, if a breaker is incapable of operating, the associated instrument channel would also be inoperable.

24

The ~~18~~ 2 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance test when performed at the ~~18~~ 2 month Frequency.

SR 3.3.4.1.5

This SR ensures that an EOC-RPT initiated from the TSV Closure and TCV Fast Closure, Trip Oil Pressure-Low Functions will not be inadvertently bypassed when THERMAL POWER is ≥ 40% RTP. This involves calibration of the bypass channels. Adequate margins for the instrument setpoint methodologies are incorporated into the actual setpoint. Because main turbine bypass flow can affect this setpoint nonconservatively (THERMAL POWER is derived from first stage pressure), the main turbine bypass valves must remain closed at THERMAL POWER ≥ 40% RTP to ensure that the calibration remains valid. If any bypass channel's setpoint is nonconservative (i.e., the Functions are bypassed at ≥ 40% RTP either due to open main turbine bypass valves or other reasons), the affected TSV Closure and TCV Fast Closure, Trip Oil Pressure-Low Functions are considered inoperable. Alternatively, the bypass channel can be placed in the conservative condition (nonbypass). If placed in the nonbypass condition, this SR is met and the channel considered OPERABLE.

24

The Frequency of ~~18~~ 2 months has shown that channel bypass failures between successive tests are rare.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.4.1.6

This SR ensures that the individual channel response times are less than or equal to the maximum values assumed in the accident analysis. The EOC-RPT SYSTEM RESPONSE TIME acceptance criteria are included in Reference 6.

A Note to the Surveillance states that breaker interruption time may be assumed from the most recent performance of SR 3.3.4.1.7. This is allowed since the time to open the contacts after energization of the trip coil and the arc suppression time are short and do not appreciably change, due to the design of the breaker opening device and the fact that the breaker is not routinely cycled.

EOC-RPT SYSTEM RESPONSE TIME tests are conducted on an 24 ~~18~~ month STAGGERED TEST BASIS. Each test shall include at least the logic of one type of channel input (Turbine Stop Valve Closure or Turbine Control Valve Fast Closure, Trip Oil Pressure - Low) such that both types of channel inputs are tested at least once per ~~36~~ 48 months. Response times cannot be determined at power because operation of final actuated devices is required. Therefore, this Frequency is consistent with the typical industry refueling cycle and is based upon plant operating experience, which shows that random failures of instrumentation components that cause serious response time degradation, but not channel failure, are infrequent occurrences.

SR 3.3.4.1.7

This SR ensures that the RPT breaker interruption time is provided to the EOC-RPT SYSTEM RESPONSE TIME test. Breaker Interruption time is defined as Breaker Response time plus Arc Suppression time. Breaker Response is the time from application of voltage to the trip coil until the arcing contacts separate. Arc Suppression is the time from arcing contact separation until the complete suppression of the electrical arc across the open contacts. Breaker Response shall be verified by testing to be within the manufacturer's design response time. Testing of the breaker response time verifies the design interruption time to be ≤ five cycles (83.3 ms). Breaker arc suppression shall be validated by visual observation of puffer performance and insulation testing of the breaker arc chutes. The 60 month Frequency of

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.4.2.4 (continued)

range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The Frequency is based upon the assumption of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.4.2.5

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The system functional test of the pump breakers, included as part of this Surveillance, overlaps the LOGIC SYSTEM FUNCTIONAL TEST to provide complete testing of the assumed safety function. Therefore, if a breaker is incapable of operating, the associated instrument channel(s) would be inoperable.

24

The ~~18~~ month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the ~~18~~ month Frequency.

REFERENCES

1. USAR, Section 7.7.1.2.
2. NEDE-770-06-1, "Bases For Changes To Surveillance Test Intervals and Allowed Out-of-Service Times For Selected Instrumentation Technical Specifications," February 1991.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.5.1.4 and SR 3.3.5.1.5

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The Frequency of SR 3.3.5.1.4 and SR 3.3.5.1.5 is based upon the assumption of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.5.1.6

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required initiation logic for a specific channel. The system functional testing performed in LCO 3.5.1, LCO 3.5.2, LCO 3.8.1, and LCO 3.8.2 overlaps this Surveillance to provide complete testing of the assumed safety function.

24

The ~~18~~ month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage (except for Division III which can be tested in any operational condition) and the potential for unplanned transients if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the ~~18~~ month Frequency.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.5.2.4 (continued)

The Frequency is based on the assumption of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.5.2.5

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required initiation logic for a specific channel. The system functional testing performed in LCO 3.5.3 overlaps this Surveillance to provide complete testing of the safety function.

24

The ~~18~~ month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the ~~18~~ month Frequency.

REFERENCES

1. NEDE-770-06-2, "Addendum to Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," February 1991.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.6.1.3 (continued)

Table 3.3.6.1-1. If the trip setting is discovered to be less conservative than accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, the channel performance is still within the requirements of the plant safety analysis. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than accounted for in the appropriate setpoint methodology.

The Frequency of 92 days is based on the reliability analysis of References 5 and 6.

SR 3.3.6.1.4 and SR 3.3.6.1.5

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The Frequency of SR 3.3.6.1.4 and SR 3.3.6.1.5 is based on the assumption of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.6.1.6

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required isolation logic for a specific channel. The system functional testing performed on PCIVs in LCO 3.6.1.3 and on drywell isolation valves in LCO 3.6.5.3 overlaps this Surveillance to provide complete testing of the assumed safety function. The ~~18~~ month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the ~~18~~ month Frequency.

24

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.1.7

This SR ensures that the individual channel response times are less than or equal to the maximum values assumed in the accident analysis. Testing is performed only on channels where the assumed response time does not correspond to the diesel generator (DG) start time. For channels assumed to respond within the DG start time, sufficient margin exists in the 10 second start time when compared to the typical channel response time (milliseconds) so as to assure adequate response without a specific measurement test. Testing of the closure times of the MSIVs is not included in this Surveillance since the closure time of the MSIVs is tested in SR 3.6.1.3.6. The instrument response times must be added to the MSIV closure times to obtain the ISOLATION SYSTEM RESPONSE TIME. ISOLATION SYSTEM RESPONSE TIME acceptance criteria for this instrumentation is included in Reference 7.

As noted the associated sensors are not required to be response time tested. Response time testing for the remaining channel components is required. This is supported by Reference 8.

ISOLATION SYSTEM RESPONSE TIME tests for this instrumentation are conducted ~~on an 18~~ 24 month STAGGERED TEST BASIS. This test Frequency is consistent with the typical industry refueling cycle and is based upon plant operating experience that shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent.

REFERENCES

1. USAR, Section 6.3.
2. USAR, Chapter 15.
3. NEDO-31466, "Technical Specification Screening Criteria Application and Risk Assessment," November 1987.
4. USAR, Section 9.3.5.
5. NEDC-31677-P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation," June 1989.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)	<u>SR 3.3.6.2.5</u> The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required isolation logic for a specific channel. The system functional testing, performed on SCIDs and the associated ventilation subsystems in LCO 3.6.4.2, LCO 3.6.4.3, LCO 3.6.4.4, LCO 3.6.4.6, and LCO 3.6.4.7, respectively, overlaps this Surveillance to provide complete testing of the assumed safety function. 24 The ~~18~~ 2 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the ~~18~~ 2 month Frequency.
REFERENCES	1. USAR, Section 6.3. 2. USAR, Chapter 15. 3. NEDC-31677-P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation," July 1990. 4. NEDC-30851-P-A Supplement 2, "Technical Specifications Improvement Analysis for BWR Isolation Instrumentations Common to RPS and ECCS Instrumentation," March 1989.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.3.5

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required initiation logic for a specific channel. The system functional testing performed in LCO 3.6.1.7, "Primary Containment Unit Coolers," overlaps this Surveillance to provide complete testing of the assumed safety function.

24

The ~~18~~ month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the ~~18~~ month Frequency.

REFERENCES

1. USAR, Section 7.3.1.1.6.
2. USAR, Section 6.2.1.1.3.
3. GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," February 1991.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.4.2

The calibration of trip units provides a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be less conservative than the Allowable Value specified in SR 3.3.6.4.3. If the trip setting is discovered to be less conservative than accounted for in the appropriate setpoint methodology but is not beyond the Allowable Value, the channel performance is still within the requirements of the plant safety analysis. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than accounted for in the appropriate setpoint methodology.

The Frequency of 92 days is based on the reliability analysis of Reference 3.

SR 3.3.6.4.3

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The Frequency is based upon the assumption of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.6.4.4

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required actuation logic for a specific channel. The system functional testing performed for S/RVs in LCO 3.4.4 and LCO 3.6.1.6 overlaps this Surveillance to provide complete testing of the assumed safety function.

24

The ~~18~~ month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the ~~18~~ month Frequency.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.7.1.3 (continued)

setpoint must be readjusted to be equal to or more conservative than accounted for in the appropriate setpoint methodology.

The Frequency of 92 days is based on the reliability analyses of References 4, 5, and 6.

SR 3.3.7.1.4

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The Frequency is based on the assumption of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.7.1.5

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required initiation logic for a specific channel. The system functional testing performed in LCO 3.7.3, "Control Room Fresh Air (CRFA) System," overlaps this Surveillance to provide complete testing of the assumed safety function.

24

The ~~18~~ month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the ~~18~~ month Frequency.

REFERENCES

1. USAR, Section 7.3.1.1.9.
2. USAR, Section 6.4.
3. USAR, Chapter 15.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.8.1.2 (continued)

The Frequency of 31 days is based on plant operating experience with regard to channel OPERABILITY and drift that demonstrates that failure of more than one channel of a given Function in any 31 day interval is rare.

SR 3.3.8.1.3

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. There is a plant specific program which verifies that the instrument channel functions as required by verifying that the as-left and as-found settings are consistent with those established by the setpoint methodology. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The Frequency is based on the assumption of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.8.1.4

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required actuation logic for a specific channel. The system functional testing performed in LCO 3.8.1 and LCO 3.8.2 overlaps this Surveillance to provide complete testing of the assumed safety functions.

24

The ~~18~~ month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the ~~18~~ month Frequency.

REFERENCES

1. USAR, Section 8.3.1.
2. USAR, Section 5.2.
3. USAR, Section 6.3.
4. USAR, Chapter 15.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.3.8.2.1

A CHANNEL FUNCTIONAL TEST is performed on each overvoltage, undervoltage, and underfrequency (including time delay) channel to ensure that the entire channel will perform the intended function.

As noted in the Surveillance, the CHANNEL FUNCTIONAL TEST is only required to be performed while the plant is in a condition in which the loss of the RPS bus will not jeopardize steady state power operation (the design of the system is such that the power source must be removed from service to conduct the Surveillance). The 24 hours is intended to indicate an outage of sufficient duration to allow for scheduling and proper performance of the Surveillance. The 184 day Frequency and the Note in the Surveillance are based on guidance provided in Generic Letter 91-09 (Ref. 2).

SR 3.3.8.2.2

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies that the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The Frequency is based upon the assumption of an ~~18~~ 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.8.2.3

Performance of a system functional test demonstrates a required system actuation (simulated or actual) signal. The logic of the system will automatically trip open the associated power monitoring assembly circuit breaker. Only one signal per power monitoring assembly is required to be tested. This Surveillance overlaps with the CHANNEL CALIBRATION to provide complete testing of the safety function. The system functional test of the Class 1E circuit breakers is included as part of this test to provide complete testing of the safety function. If the breakers are incapable of operating, the associated electric power monitoring assembly would be inoperable.

24

The ~~18~~ month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the ~~18~~ month Frequency.

REFERENCES

1. USAR, Section 8.3.1.1.3.
2. NRC Generic Letter 91-09, "Modification of Surveillance Interval for the Electric Protective Assemblies in Power Supplies for the Reactor Protection System."

BASES

ACTIONS (continued)

B.1

If the FCVs are not deactivated (locked up) and cannot be restored to OPERABLE status within the associated Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 12 hours. This brings the unit to a condition where the flow coastdown characteristics of the recirculation loop are not important. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1

Hydraulic power unit pilot operated isolation valves located between the servo valves and the common "open" and "close" lines are required to close in the event of a loss of hydraulic pressure. When closed, these valves inhibit FCV motion by blocking hydraulic pressure from the servo valve to the common open and close lines as well as to the alternate subloop. This Surveillance verifies FCV lockup on a loss of hydraulic pressure.

The ~~18~~ 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the SR when performed at the ~~18~~ 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.4.2.2

This SR ensures the overall average rate of FCV movement at all positions is maintained within the analyzed limits.

The ~~18~~ 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.2.2 (continued)

Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the SR when performed at ~~the~~ ~~18~~ 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. USAR, Section 15.3.2.

2. USAR, Section 15.4.5.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.4.1 (continued)

lift settings must be performed during shutdown, since this is a bench test, and in accordance with the Inservice Testing Program. The lift setting pressure shall correspond to ambient conditions of the valves at nominal operating temperatures and pressures.

The Frequency was selected because this Surveillance must be performed during shutdown conditions and is based on the time between refuelings.

SR 3.4.4.2

The required relief function S/RVs are required to actuate automatically upon receipt of specific initiation signals. A system functional test is performed to verify the mechanical portions of the automatic relief function operate as designed when initiated either by an actual or simulated initiation signal. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.4.4 overlaps this SR to provide complete testing of the safety function.

24

The ~~18~~ 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the SR when performed at the ~~18~~ 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note that excludes valve actuation. This prevents an RPV pressure blowdown.

SR 3.4.4.3

A manual actuation of each required S/RV (those valves removed and replaced to satisfy SR 3.4.4.1) is performed to verify that the valve is functioning properly. This SR can be demonstrated by one of two methods. If performed by method 1), plant startup is allowed prior to performing this test because valve OPERABILITY and the setpoints for overpressure protection are verified, per ASME requirements (Ref. 1), prior to valve installation. Therefore, this SR is modified by a note that states the surveillance is not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. The 12 hours allowed for manual actuation after the required pressure is reached is sufficient to achieve stable conditions for testing and provides

(continued)

BASES

ACTIONS (continued)

F.1

With all required monitors inoperable, no required automatic means of monitoring LEAKAGE are available, and immediate plant shutdown in accordance with LCO 3.0.3 is required.

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1

This SR requires the performance of a CHANNEL CHECK of the required drywell atmospheric monitoring system. The check gives reasonable confidence that the channel is operating properly. The Frequency of 12 hours is based on instrument reliability and is reasonable for detecting off normal conditions.

SR 3.4.7.2

This SR requires the performance of a CHANNEL FUNCTIONAL TEST of the required RCS leakage detection instrumentation. The test ensures that the monitors can perform their function in the desired manner. The test also verifies the relative accuracy of the instrumentation. The Frequency of 31 days considers instrument reliability, and operating experience has shown it proper for detecting degradation.

SR 3.4.7.3

This SR requires the performance of a CHANNEL CALIBRATION of the required RCS leakage detection instrumentation channels. The calibration verifies the accuracy of the instrumentation, including the instruments located inside the drywell. The Frequency of ~~18~~ months is a typical refueling cycle and considers channel reliability. Operating experience has proven this Frequency is acceptable.

24

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.4 (continued)

The pump flow rates are verified with a pump differential pressure that is sufficient to overcome the RPV pressure expected during a LOCA. The total system pump outlet pressure is adequate to overcome the elevation head pressure between the pump suction and the vessel discharge, the piping friction losses, and RPV pressure present during LOCAs. These values may be established during pre-operational testing. The Frequency for this Surveillance is in accordance with the Inservice Testing Program requirements.

SR 3.5.1.5

The ECCS subsystems are required to actuate automatically to perform their design functions. This Surveillance test verifies that, with a required system initiation signal (actual or simulated), the automatic initiation logic of HPCS, LPCS, and LPCI will cause the systems or subsystems to operate as designed, including actuation of the system throughout its emergency operating sequence, automatic pump startup, and actuation of all automatic valves in the flow path to their required positions. This test may be performed by means of any series of sequential, overlapping, or total system steps so that the entire system is tested. This Surveillance also ensures that the HPCS System will automatically restart on an RPV low water level (Level 2) signal received subsequent to an RPV high water level (Level 8) trip and that the suction is automatically transferred from the CST to the suppression pool. The LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.1, "Emergency Core Cooling System (ECCS) Instrumentation," overlaps this Surveillance to provide complete testing of the assumed safety function.

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage (except for Division III which can be tested in any operational condition) and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the SR when performed at the 18 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

(continued)

24

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.5 (continued)

This SR is modified by a Note that excludes vessel injection/spray during the Surveillance. Since all active components are testable and full flow can be demonstrated by recirculation through the test line, coolant injection into the RPV is not required during the Surveillance.

SR 3.5.1.6

The ADS designated S/RVs are required to actuate automatically upon receipt of specific initiation signals. A system functional test is performed to demonstrate that the mechanical portions of the ADS function (i.e., solenoids) operate as designed when initiated either by an actual or simulated initiation signal, causing proper actuation of all the required components. SR 3.5.1.7 and the LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.1 overlap this Surveillance to provide complete testing of the assumed safety function.

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the SR when performed at the 18 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note that excludes valve actuation. This prevents an RPV pressure blowdown.

SR 3.5.1.7

A manual actuation of each required ADS valve (those valves removed and replaced to satisfy SR 3.4.4.1) is performed to verify that the valve is functioning properly. This SR can be demonstrated by one of two methods. If performed by method 1), plant startup is allowed prior to performing this test because valve OPERABILITY and the setpoints for overpressure protection are verified, per ASME requirements (Ref. 16) prior to valve installation. Therefore, this SR is modified by a note that states the surveillance is not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. The 12 hours allowed for manual actuation after the required pressure is reached is sufficient to achieve stable conditions for testing and provides a reasonable time to complete the SR. If performed by method 2), valve

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.7 (continued)

implemented by the Inservice Testing Program of Specification 5.5.6. The testing frequency required by the Inservice Testing Program is based on operating experience and valve performance. Therefore, the frequency was concluded to be acceptable from a reliability standpoint.

SR 3.5.1.8

This SR ensures that the ECCS RESPONSE TIMES are within limits for each of the ECCS injection and spray subsystems. This SR is modified by a Note which identifies that the associated ECCS actuation instrumentation is not required to be response time tested. Response time testing of the remaining subsystem components is required. This is supported by Reference 14. Response time testing acceptance criteria are included in Reference 15.

ECCS RESPONSE TIME tests are conducted every ~~18~~ months. The ~~18~~ month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the SR when performed at the ~~18~~ month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

24

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.3.3 and SR 3.5.3.4

The RCIC pump flow rates ensure that the system can maintain reactor coolant inventory during pressurized conditions with the RPV isolated. The flow tests for the RCIC System are performed at two different pressure ranges such that system capability to provide rated flow is tested both at the higher and lower operating ranges of the system. Additionally, adequate steam flow must be passing through the main turbine or turbine bypass valves to continue to control reactor pressure when the RCIC System diverts steam flow. Since the required reactor steam pressure must be available to perform SR 3.5.3.3 and SR 3.5.3.4, sufficient time is allowed after adequate pressure and flow are achieved to perform these SRs. Reactor startup is allowed prior to performing the low pressure Surveillance because the reactor pressure is low and the time to satisfactorily perform the Surveillance is short. The reactor pressure is allowed to be increased to normal operating pressure since it is assumed that the low pressure test has been satisfactorily completed and there is no indication or reason to believe that RCIC is inoperable. Therefore, these SRs are modified by Notes that state the Surveillances are not required to be performed until 12 hours after the reactor steam pressure and flow are adequate to perform the test.

A 92 day Frequency for SR 3.5.3.3 is consistent with the Inservice Testing Program requirements. The ~~18~~ 24 month Frequency for SR 3.5.3.4 is based on the need to perform this Surveillance under the conditions that apply just prior to or during startup from a plant outage. Operating experience has shown that these components usually pass the SR when performed at the ~~18~~ 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.5.3.5

The RCIC System is required to actuate automatically to perform its design function. This Surveillance verifies that with a required system initiation signal (actual or simulated) the automatic initiation logic of RCIC will cause the system to operate as designed, including actuation of the system throughout its emergency operating sequence,

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.3.5 (continued)

automatic pump startup and actuation of all automatic valves to their required positions. This Surveillance test also ensures that the RCIC System will automatically restart on an RPV low water level (Level 2) signal received subsequent to an RPV high water level (Level 8) trip and that the suction is automatically transferred from the CST to the suppression pool. The LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.2, "Reactor Core Isolation Cooling (RCIC) System Instrumentation," overlaps this Surveillance to provide complete testing of the assumed safety function.

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the SR when performed at the 18 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note that excludes vessel injection during the Surveillance. Since all active components are testable and full flow can be demonstrated by recirculation through the test line, coolant injection into the RPV is not required during the Surveillance.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 33.
2. USAR, Section 5.4.6.2.
3. Memorandum from R.L. Baer (NRC) to V. Stello, Jr. (NRC), "Recommended Interim Revisions to LCO's for ECCS Components," December 1, 1975.
4. USAR, Section 5.4.6.1

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.3.7

Automatic PCIVs close on a primary containment isolation signal to prevent leakage of radioactive material from primary containment following a DBA. This SR ensures that each automatic PCIV will actuate to its isolation position on a primary containment isolation signal. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.1.6 overlaps this SR to provide complete testing of the safety function. The ~~18~~ month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass this Surveillance when performed at the ~~18~~ month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.1.3.8 24

The use of MS-PLCS as a positive leakage barrier results in in-leakage and gradual pressure buildup within the containment. The total allowable MSIV in-leakage rate does not have radiological consequences. This surveillance ensures that the total allowable air in-leakage rate is limited such that containment pressurization does not exceed 50 percent of the design value in a 30 day period due to these sources. 24

The ~~18 month Frequency~~ is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass this Surveillance when performed at the ~~18~~ month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.1.3.9

This SR ensures that the leakage rate of secondary containment bypass leakage paths is less than the specified leakage rate when pressurized to ≥ P_a, 7.6 psig. This provides assurance that the assumptions in the radiological

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.7.2

Verifying each unit cooler develops a flow rate ≥ 50,000 cfm ensures overall performance has not degraded during the cycle. Such inservice tests confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. The Frequency of this SR is consistent with that applied to pumps by the Inservice Testing Program.

SR 3.6.1.7.3

This SR verifies that each primary containment unit cooler actuates upon receipt of an actual or simulated automatic actuation signal throughout its' emergency operating sequence and that the pressure relief and backdraft damper in the flow path actuates to its' correct position. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.3.5 overlaps this SR to provide complete testing of the safety function. The ~~18~~ month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the ~~18~~ month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. USAR, Section 6.2.1.1.3.4.

24

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.9.1 (continued)

from the PVLCS accumulators. Due to the support system function of PVLCS for S/RV actuator air, however, the specified minimum pressure of 101 psig is required, which provides sufficient air for intermediate and long term post-LOCA S/RV actuations. This minimum air pressure alone is sufficient for PVLCS to support the OPERABILITY of these S/RV systems and is verified every 24 hours. The 24 hour Frequency is considered adequate in view of other indications available in the control room, such as alarms, to alert the operator to an abnormal PVLCS air pressure condition.

SR 3.6.1.9.2

Each PVLCS compressor is operated for ≥ 15 minutes to verify MS-PLCS OPERABILITY. The 31 day Frequency was developed considering the known reliability of the PVLCS compressor and controls, the two subsystem redundancy, and the low probability of a significant degradation of the MS-PLCS subsystem occurring between surveillances and has been shown to be acceptable through operating experience.

SR 3.6.1.9.3 24

A system functional test is performed to ensure that the MS-PLCS will operate through its operating sequence. The ~~18~~ month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the ~~18~~ month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. USAR, Section 6.7.
2. USAR, Section 15.6.5.

BASES

ACTIONS

C.1 (continued)

operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.3.2.1 and SR 3.6.3.2.2

These SRs verify that there are no physical problems that could affect the igniter operation. Since the igniters are mechanically passive, they are not subject to mechanical failure. The only credible failures are loss of power or burnout. The verification that each required igniter is energized is performed by circuit current versus voltage measurement of each circuit.

24

The Frequency of 184 days has been shown to be acceptable through operating experience because of the low failure occurrence, and provides assurance that hydrogen burn capability exists between the more rigorous ~~18~~ month Surveillances. Operating experience has shown these components usually pass the Surveillance when performed at a 184 day Frequency. Additionally, these surveillances must be performed every 92 days if four or more igniters in any division are inoperable. The 92 day Frequency was chosen, recognizing that the failure occurrence is higher than normal. Thus, decreasing the Frequency from 184 days to 92 days is a prudent measure, since only two more inoperable igniters (for a total of six) will result in an inoperable igniter division. SR 3.6.3.2.2 is modified by a Note that indicates that the Surveillance is not required to be performed until 92 days after four or more igniters in the division are discovered to be inoperable.

SR 3.6.3.2.3 and SR 3.6.3.2.4 24

These functional tests are performed every ~~18~~ months to verify system OPERABILITY. The current draw to develop a surface temperature of ≥ 1700°F is verified for igniters in inaccessible areas. Inaccessible areas are defined as areas that have high radiation levels during the entire refueling outage period. These areas are the heat exchanger, filter demineralizer, backwash, and holding pump rooms of the RWCU system. Additionally, the surface temperature of each accessible igniter is verified to be ≥ 1700°F to demonstrate

(continued)

24

BASES

SURVEILLANCE REQUIREMENTS	<u>SR 3.6.3.2.3 and SR 3.6.3.2.4</u> (continued) that a temperature sufficient for ignition is achieved. The ~~18~~ month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the ~~18~~ month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.
REFERENCES	1. 10 CFR 50.44. 2. 10 CFR 50, Appendix A, GDC 41. 3. USAR, Section 6.2.5.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.3.3.1 (continued)

and 3, because these valves have never been demonstrated capable of closing during accident conditions in the drywell (Reference 3). The 92 day frequency is consistent with operating experience, the known reliability of the fan and controls, and the two redundant subsystems available.

SR 3.6.3.3.2

24

Verifying that each primary containment/drywell hydrogen mixing subsystem flow rate is ≥ 600 cfm ensures that each subsystem is capable of maintaining drywell hydrogen concentrations below the flammability limit. The ~~18~~ month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage when the drywell boundary is not required. Operating experience has shown that these components usually pass the Surveillance when performed at the ~~18~~ month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. Regulatory Guide 1.7, Revision 2.
2. USAR, Section 6.2.5.
3. CR 96-0767.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.4.2.2

Verifying that each required automatic SCID and FBID closes on an isolation signal is required to prevent leakage of radioactive material from secondary containment or fuel building following a DBA or other accidents. This SR ensures that each automatic SCID will actuate to the isolation position on a secondary containment isolation signal and that each FBID will actuate on a fuel building isolation signal. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.2.5 overlaps this SR to provide complete testing of the safety function. The ~~18~~ month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the ~~18~~ month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

24

REFERENCES

1. USAR, Section 15.6.5.
2. USAR, Section 6.2.3.
3. USAR, Section 15.7.4.
4. TRM, Table 3.6.4.2-1.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.4.3.1

Operating each SGT subsystem for ≥ 10 continuous hours ensures that both subsystems are OPERABLE and that all associated controls are functioning properly. It also ensures that blockage, fan or motor failure, or excessive vibration can be detected for corrective action. Operation with the heaters on (automatic heater cycling to maintain temperature) for ≥ 10 continuous hours every 31 days eliminates moisture on the adsorbers and HEPA filters. The 31 day Frequency was developed in consideration of the known reliability of fan motors and controls and the redundancy available in the system.

SR 3.6.4.3.2

This SR verifies that the required SGT filter testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The SGT System filter tests are in accordance with Regulatory Guide 1.52 (Ref. 4). The VFTP includes testing HEPA filter performance, charcoal adsorber efficiency, minimum system flow rate, and the physical properties of the activated charcoal (general use and following specific operations). Specified test frequencies and additional information are discussed in detail in the VFTP.

SR 3.6.4.3.3

This SR requires verification that each SGT subsystem starts upon receipt of an actual or simulated initiation signal. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.2.5 overlaps this SR to provide complete testing of the safety function. While this Surveillance can be performed with the reactor at power, operating experience has shown these components usually pass the Surveillance when performed at the 24 ~~18~~ month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.4.3.4

This SR requires verification that the SGT filter cooling bypass damper can be opened and the fan started. This ensures that the ventilation mode of SGT System operation is

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.4.3.4 (continued) 24

available. While this Surveillance can be performed with the reactor at power, operating experience has shown these components usually pass the Surveillance when performed at the ~~18~~ month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 41.
2. USAR, Section 6.2.3.
3. USAR, Section 15.6.5.
4. Regulatory Guide 1.52, Rev. 2.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.4.7.2

Operating each fuel building ventilation charcoal filtration subsystem for ≥ 10 continuous hours ensures that both subsystems are OPERABLE and that all associated controls are functioning properly. It also ensures that blockage, fan or motor failure, or excessive vibration can be detected for corrective action. Operation with the heaters operating (automatic heater cycling to maintain temperature) for ≥ 10 continuous hours every 31 days eliminates moisture on the adsorbers and HEPA filters. The 31 day Frequency was developed in consideration of the known reliability of fan motors and controls and the redundancy available in the system.

SR 3.6.4.7.3

This SR verifies that the required fuel building ventilation charcoal filtration filter testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The fuel building ventilation charcoal filtration filter tests are in accordance with Regulatory Guide 1.52 (Ref. 4). The VFTP includes testing HEPA filter performance, charcoal adsorber efficiency, minimum system flow rate, and the physical properties of the activated charcoal (general use and following specific operations). Specified test frequencies and additional information are discussed in detail in the VFTP.

SR 3.6.4.7.4

This SR requires verification that each fuel building ventilation charcoal filtration subsystem starts upon receipt of an actual or simulated initiation signal. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.2.5 overlaps this SR to provide complete testing of the safety function. While this Surveillance can be performed with the reactor at power, operating experience has shown these components usually pass the Surveillance when performed at the ~~18~~ month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

(continued)

24

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.4.7.5

This SR requires verification that the fuel building ventilation charcoal filtration filter cooling bypass damper can be opened and the fan started. This ensures that the ventilation mode of Fuel Building Ventilation System operation is available. While this Surveillance can be performed with the reactor at power, operating experience has shown these components usually pass the Surveillance when performed at the ~~18~~ month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

24

REFERENCES

1. 10 CFR 50, Appendix A, GDC 41.
2. USAR, Section 6.2.3.
3. USAR, Section 15.6.5.
4. Regulatory Guide 1.52, Rev. 2.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.5.3.4

be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable since access to these areas is typically restricted during MODES 1, 2, and 3. Therefore, the probability of misalignment of these devices, once they have been verified to be in their proper position, is low. A second Note is included to clarify that the drywell isolation valves that are open under administrative controls are not required to meet the SR during the time that the devices are open.

Verifying that the isolation time of each power operated and each automatic drywell isolation valve is within limits is required to demonstrate OPERABILITY. The isolation time test ensures the valve will isolate in a time period less than or equal to that assumed in the safety analysis. The isolation time and Frequency of this SR are in accordance with the Inservice Testing Program.

SR 3.6.5.3.5

Verifying that each automatic drywell isolation valve closes on a drywell isolation signal is required to prevent bypass leakage from the drywell following a DBA. This SR ensures each automatic drywell isolation valve will actuate to its isolation position on a drywell isolation signal. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.1.6 overlaps this SR to provide complete testing of the safety function. The ~~18 month~~ Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power, since isolation of penetrations would eliminate cooling water flow and disrupt the normal operation of many critical components. Operating experience has shown these components usually pass this Surveillance when performed at the ~~18 month~~ Frequency. Therefore, the Frequency was concluded to be ~~acceptable from a reliability standpoint.~~

24

SR 3.6.5.3.6

This SR ensures that the hydrogen mixing valves remain closed during Modes 1, 2, and 3, or, if open, are only open for a limited period of time over a 365 day cycle. Since

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.1.4 (continued)

those valves capable of potentially being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

Isolation of the SSW subsystem to components or systems does not necessarily affect the OPERABILITY of the SSW System. As such, when all SSW pumps, valves, and piping are OPERABLE, but a branch connection off the main header is isolated, the SSW subsystem needs to be evaluated to determine if it is still OPERABLE.

The 31 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions.

SR 3.7.1.5

This SR verifies that the automatic isolation valves of the SSW System will automatically switch to the safety or emergency position to provide cooling water exclusively to the safety related equipment during an accident event. This is demonstrated by use of an actual or simulated initiation signal. This SR also verifies the automatic start capability of the SSW pump and cooling tower fans in each subsystem. Any series of sequential or overlapping steps which demonstrate the required function may be used to satisfy this requirement.

Operating experience has shown that these components usually pass the SR when performed on ~~the 18~~ 24 month Frequency. Therefore, this Frequency is concluded to be acceptable from a reliability standpoint.

REFERENCES

1. Regulatory Guide 1.27, Revision 2, January 1976.
2. USAR, Section 9.2.
3. USAR, Table 9.2-15.
4. USAR, Section 6.2.1.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.2.2

This SR verifies that the required CRFA testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The CRFA filter tests are in accordance with Regulatory Guide 1.52 (Ref. 5). The VFTP includes testing HEPA filter performance, charcoal adsorber efficiency, minimum system flow rate, and the physical properties of the activated charcoal (general use and following specific operations). Specific test Frequencies and additional information are discussed in detail in the VFTP.

SR 3.7.2.3

This SR verifies that each CRFA subsystem starts and operates on an actual or simulated initiation signal. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.7.1.5 overlaps this SR to provide complete testing of the safety function. While this Surveillance can be performed with the reactor at power, operating experience has shown these components usually pass the Surveillance when performed at the ~~18~~ month Frequency, which is based on the refueling cycle. Therefore, ~~the Frequency~~ was concluded to be acceptable from a reliability standpoint.

24

SR 3.7.2.4

This SR verifies the OPERABILITY of the CRE boundary by testing for unfiltered air inleakage past the CRE boundary and into the CRE. The details of the testing are specified in the Control Room Envelope Habitability Program.

The CRE is considered habitable when the radiological dose to CRE occupants calculated in the licensing basis analyses of DBA consequences is no more than 5 rem TEDE and the CRE occupants are protected from hazardous chemicals and smoke. This SR verifies that the unfiltered air inleakage into the CRE is no greater than the flow rate assumed in the licensing basis analyses of DBA consequences. When unfiltered air inleakage is greater than the assumed flow rate, Condition B must be entered. Required Action B.3 allows time to restore the CRE boundary to OPERABLE status provided mitigating actions can ensure that the CRE remains within the licensing basis habitability limits for the occupants following an accident. Compensatory measures are discussed in Regulatory Guide 1.196, Section C.2.7.3, (Ref. 7) which endorses, with exceptions, NEI 99-03, Section 8.4 and Appendix F (Ref. 8). These compensatory measures may also be used as mitigating actions as required by Required Action B.2. Temporary analytical methods may also be used as compensatory measures to restore OPERABILITY (Ref. 9). Options for restoring the CRE boundary to OPERABLE status include changing the licensing basis DBA consequence analysis, repairing the CRE boundary, or a combination of these actions. Depending upon the nature of the problem and the corrective action, a full scope inleakage test may not be necessary to establish that the CRE boundary has been restored to OPERABLE status.

(continued)

BASES

ACTIONS

E.1 and E.2 (continued)

not preclude completion of movement of a component to a safe position. Also, if applicable, actions must be initiated immediately to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until the OPDRVs are suspended.

SURVEILLANCE REQUIREMENTS

SR 3.7.3.1

This SR verifies that the heat removal capability of the system is sufficient to remove the control room heat load assumed in the safety analysis. The SR consists of a combination of testing and calculation. The ~~18~~ 24 month Frequency is appropriate since significant degradation of the Control Room AC System is not expected over this time period.

REFERENCES

1. USAR, Section 6.4.
2. USAR, Section 9.4.1.

BASES

ACTIONS

B.1 (continued)

sufficient margin to the required limits, and the Main Turbine Bypass System is not required to protect fuel integrity during the feedwater controller failure, maximum demand event. The 4 hour Completion Time is reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.5.1

Cycling each main turbine bypass valve through one complete cycle of full travel demonstrates that the valves are mechanically OPERABLE and will function when required. The 31 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions. Therefore, the Frequency is acceptable from a reliability standpoint.

SR 3.7.5.2

The Main Turbine Bypass System is required to actuate automatically to perform its design function. This SR demonstrates that, with the required system initiation signals, the valves will actuate to their required position. The ~~18~~ month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and because of the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown the ~~18~~ month Frequency, which is based on the refueling cycle, is acceptable from a reliability standpoint.

24

SR 3.7.5.3

This SR ensures that the TURBINE BYPASS SYSTEM RESPONSE TIME is in compliance with the assumptions of the appropriate safety analysis. The response time limits are specified in applicable surveillance test procedures. The ~~18~~ month Frequency is based on the need to perform this Surveillance

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.5.3 (continued)

under the conditions that apply during a unit outage and because of the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown the ~~18~~ month Frequency, which is based on the refueling cycle, is acceptable from a reliability standpoint.

24

REFERENCES

1. USAR, Section 7.7.1.4.
2. USAR, Section 15.1.2.

BASES

ACTIONS

B.3.1 and B.3.2 (continued)

is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DG(s), performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of those DG(s).

In the event the inoperable DG is restored to OPERABLE status prior to completing either B.3.1 or B.3.2, the Condition Report Program will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition B.

According to Generic Letter 84-15 (Ref. 7), 24 hours is reasonable time to confirm that the OPERABLE DG(s) are not affected by the same problem as the inoperable DG.

B.4

In Condition B, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E distribution system. Although Condition B applies to a single inoperable DG, several Completion Times are Specified for this Condition. The first completion time applies to an inoperable Division III DG. The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and low probability of a DBA occurring during this period. This Completion Time begins only "upon discovery of an inoperable Division III DG" and, as such, provides an exception to the normal "time zero" for beginning the allowed outage time "clock" (i.e., for beginning the clock for an inoperable Division III DG when Condition B may have already been entered for another equipment inoperability and is still in effect).

The second Completion Time (14 days) applies to an inoperable Division I or Division II DG and is risk-informed allowed out-of-service time (AOT) based on plant specific risk analysis. The extended AOT would typically be use for voluntary planned maintenance or inspections but can also be used for corrective maintenance. However, use of the extended AOT for voluntary planned maintenance should be limited to once within an operating cycle (~~18~~ months) for each DG (Division I and Division II). Additional contingencies are to be in place for any extended AOT duration (greater than 72 hours and up to 14 days) as follows:

24

1. An DG extended AOT will not be entered for voluntary planned maintenance purposes if severe weather conditions are expected.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.7

See SR 3.8.1.2

SR 3.8.1.8

Transfer of each 4.16 kV ESF bus power supply from the normal offsite circuit to the alternate offsite circuit demonstrates the OPERABILITY of the alternate circuit. This SR applies to Divisions 1, 2, and 3. The ~~18~~ 24 month Frequency of the Surveillance is based on engineering judgment taking into consideration the plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed on the ~~18~~ month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note. The reason for the Note is that, during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems. Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post corrective maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.9

Each DG is provided with an engine overspeed trip to prevent damage to the engine. Recovery from the transient caused by the loss of a large load could cause diesel engine overspeed, which, if excessive, might result in a trip of the engine. This Surveillance demonstrates the DG load response characteristics and capability to reject the largest single load while maintaining a specified margin to the overspeed trip. The referenced load for DG 1A is the 917.5 kW low pressure core spray pump; for DG 1B, the 462.2 kW residual heat removal (RHR) pump; and for DG 1C the 1995 kW HPCS pump. The Standby Service Water (SSW) pump values are not used as the largest load since the SSW supplies cooling to the associated DG. If this load were to trip, it would result in the loss of the DG. As required by IEEE-308 (Ref. 13), the load rejection test is acceptable if the increase in diesel speed does not exceed 75% of the difference between synchronous speed and the overspeed trip setpoint, or 15% above synchronous speed, whichever is lower. For the River Bend Station the lower value results from the first criteria. The ~~18~~ 24 month frequency is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9).

This SR has been modified by two Notes. The reason for Note 1 is that credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post corrective maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, Note 2 requires that, if synchronized to offsite power, testing be performed using a power factor ≤ 0.9. This power factor is chosen to be representative of the actual design basis inductive loading that the DG could experience.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.10

This Surveillance demonstrates the DG capability to reject a full load, i.e., maximum expected accident load, without overspeed tripping or exceeding the predetermined voltage limits. The DG full load rejection may occur because of a system fault or inadvertent breaker tripping. This Surveillance ensures proper engine generator load response under the simulated test conditions. This test simulates the loss of the total connected load that the DG experiences following a full load rejection and verifies that the DG does not trip upon loss of the load. These acceptance criteria provide DG damage protection. While the DG is not expected to experience this transient during an event and continue to be available, this response ensures that the DG is not degraded for future application, including reconnection to the bus if the trip initiator can be corrected or isolated.

In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, testing must be performed using a power factor ≤ 0.9. This power factor is chosen to be representative of the actual design basis inductive loading that the DG would experience.

24

The ~~18~~ month Frequency is consistent with the recommendation of Regulatory Guide 1.108 (Ref. 9) and is intended to be consistent with expected fuel cycle lengths.

This SR has been modified by a Note. The reason for the Note is that credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post corrective maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.11

As required by Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(1), this Surveillance demonstrates the as designed operation of the standby power sources during loss of the offsite source. This test verifies all actions encountered from the loss of offsite power, including shedding of the Division I and II nonessential loads and energization of the emergency buses and respective loads from the DG. It further demonstrates the capability of the DG to automatically achieve the required voltage and frequency within the specified time.

The DG auto-start time of 10 seconds for DG 1A and DG 1B and 13 seconds for DG 1C is derived from requirements of the accident analysis to respond to a design basis large break LOCA. The Surveillance should be continued for a minimum of 5 minutes in order to demonstrate that all starting transients have decayed and stability has been achieved.

The requirement to verify the connection and power supply of permanent and auto-connected loads is intended to satisfactorily show the relationship of these loads to the DG loading logic. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, ECCS injection valves are not desired to be stroked open, systems are not capable of being operated at full flow, or RHR systems performing a decay heat removal function are not desired to be realigned to the ECCS mode of operation. In lieu of actual demonstration of the connection and loading of these loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

24

The Frequency of ~~18~~ months is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(1), takes into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.12 (continued)

The Frequency of ~~18~~ 24 months takes into consideration plant conditions required to perform the Surveillance and is intended to be consistent with the expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the ~~18~~ 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations for DG 1A and DG 1B. For DG 1C, standby conditions mean that the lube oil is heated by the jacket water and continuously circulated through a portion of the system as recommended by the vendor. Engine jacket water is heated by an immersion heater and circulates through the system by natural circulation. (Note 2 is not applicable to DG1C) The reason for Note 2 is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems. Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post corrective maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

SR 3.8.1.13

This Surveillance demonstrates that DG non-critical protective functions (e.g., high jacket water temperature)

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.13 (continued)

are bypassed on an ECCS initiation test signal and critical protective functions trip the DG to avert substantial damage to the DG unit. The non-critical trips are bypassed during DBAs and provide alarms on abnormal engine conditions. These alarms provide the operator with necessary information to react appropriately. The DG availability to mitigate the DBA is more critical than protecting the engine against minor problems that are not immediately detrimental to emergency operation of the DG.

The ~~18~~ month Frequency is based on engineering judgment, taking into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when ~~performed at the~~ ~~18~~ month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

24

The SR is modified by a Note. (The Note is not applicable to DG1C) The reason for the Note is that performing the Surveillance removes a required DG from service. Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post corrective maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

24

SR 3.8.1.14

Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(3), requires demonstration once per ~~18~~ months that the DGs can start and run continuously at full load capability for an interval of not less than 24 hours-22 hours of which is at a load

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.14 (continued)

equivalent to the continuous rating of the DG, and 2 hours of which is at a load equivalent to 110% of the continuous duty rating of the DG. An exception to the loading requirements is made for DG 1A and DG 1B. DG 1A and DG 1B are operated for 24 hours at a load greater than or equal to the maximum expected post accident load. Load carrying capability testing of the Transamerica Delaval Inc. (TDI) diesel generators (DG 1A and DG 1B) has been limited to a load less than that which corresponds to 201 psig brake mean effective pressure (BMEP). Therefore, full load testing is performed at a load ≥ 3030 kW but < 3130 kW. The DG starts for this Surveillance can be performed either from standby or hot conditions. The provisions for prelube and warmup, discussed in SR 3.8.1.2, and for gradual loading, discussed in SR 3.8.1.3, are applicable to this SR.

In order to ensure that the DG is tested under load conditions that are as close to design conditions as possible, testing must be performed using a power factor ≤ 0.9. This power factor is chosen to be representative of the actual design basis inductive loading that the DG could experience.

24

The ~~18~~ month Frequency is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(3); takes into consideration plant conditions required to perform the Surveillance; and is intended to be consistent with expected fuel cycle lengths.

This Surveillance is modified by two Notes. Note 1 states that momentary transients due to changing bus loads do not invalidate this test. The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY. Similarly, momentary power factor transients above the limit do not invalidate the test. The reason for Note 2 is that credit may be taken for unplanned events

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.14 (continued)

that satisfy this SR. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post corrective maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

SR 3.8.1.15

This Surveillance demonstrates that the diesel engine can restart from a hot condition, such as subsequent to shutdown from normal Surveillances, and achieve the required voltage and frequency within 10 seconds for DG 1A and DG 1B and within 13 seconds for DG 1C. The time requirements are derived from the requirements of the accident analysis to respond to a design basis large break LOCA.

24

The ~~18~~ 2 month Frequency is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(5).

This SR has been modified by two Notes. Note 1 ensures that the test is performed with the diesel sufficiently hot. The requirement that the diesel has operated for at least 1 hour at full load conditions prior to performance of this Surveillance and longer if necessary to stabilize the operating temperature, is based on manufacturer recommendations for achieving hot conditions. The load band is provided to avoid routine overloading of the DG. Routine overloads may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY. Momentary transients due to changing bus loads do not invalidate this test. Note 2 allows all DG starts to be preceded by an engine prelube period to minimize wear and tear on the diesel during testing.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.16

As required by Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(6), this Surveillance ensures that the manual synchronization and load transfer from the respective DG to each required offsite power source can be made and that the respective DG can be returned to ready-to-load status when offsite power is restored. It also ensures that the undervoltage logic is reset to allow the DG to reload if a subsequent loss of offsite power occurs. The DG is considered to be in ready-to-load status when the DG is at rated speed and voltage, the output breaker is open and can receive an auto-close signal on bus undervoltage, and the load sequence timers are reset.

Portions of the synchronization circuit are associated with the DG and portions with the respective offsite circuit. If a failure in the synchronization requirement of the Surveillance occurs, depending on the specific affected portion of the synchronization circuit, either the DG or the associated offsite circuit is declare inoperable.

24

The Frequency of ~~18~~ months is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(6), and takes into consideration plant conditions required to perform the Surveillance.

This SR is modified by a Note. (The Note is not applicable to DG1C) The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post corrective maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.17

Demonstration of the test mode override ensures that the DG availability under accident conditions is not compromised as the result of testing. Interlocks to the LOCA sensing circuits cause the DG to automatically reset to ready-to-load operation if an ECCS initiation signal is received during operation in the test mode. Ready-to-load operation is defined as the DG running at rated speed and voltage with the DG output breaker open. These provisions for automatic switchover are required by IEEE-308 (Ref. 13), paragraph 6.2.6(2).

The requirement to automatically energize the emergency loads with offsite power is essentially identical to that of SR 3.8.1.13. The intent in the requirement associated with SR 3.8.1.18.b is to show that the emergency loading is not affected by the DG operation in test mode. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the emergency loads to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

24

The ~~18~~ month Frequency is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(8); takes into consideration plant conditions required to perform the Surveillance; and is intended to be consistent with expected fuel cycle lengths.

This SR has been modified by a Note. (The Note is not applicable to DG1C) The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.17 (continued)

2) Post corrective maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

SR 3.8.1.18

Under accident conditions, loads are sequentially connected to the bus by the load sequencing logic. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading of the bus power supply due to high motor starting currents. The 10% load sequence time tolerance ensures that sufficient time exists for the bus power supply to restore frequency and voltage prior to applying the next load and that safety analysis assumptions regarding ESF equipment time delays are not violated. (Note that this surveillance requirement pertains only to the load sequence timer itself, and not to the interposing logic which comprises the remainder of the circuit.) Reference 2 provides a summary of the automatic loading of ESF buses.

24

The Frequency ~~of 18~~ months is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(2); takes into consideration plant conditions required to perform the Surveillance; and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by a Note. (The Note is not applicable to DG1C) The reason for the Note is that performing the Surveillance during these MODES would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge plant safety systems. Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.18 (continued)

2) Post corrective maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

SR 3.8.1.19

In the event of a DBA coincident with a loss of offsite power, the DGs are required to supply the necessary power to ESF systems so that the fuel, RCS, and containment design limits are not exceeded.

This Surveillance demonstrates the DG operation, as discussed in the Bases for SR 3.8.1.12, during a loss of offsite power actuation test signal in conjunction with an ECCS initiation signal. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

24

The Frequency ~~of 18~~ 2 months takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with an expected fuel cycle length ~~of~~ 18 months.

This SR is modified by two Notes. (Note 2 is not applicable to DG1C) The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations for DG 1A and DG 1B. For DG 1C, standby conditions mean that the lube oil is heated by the jacket water and continuously circulated through a portion of the system as recommended by the vendor. Engine jacket water is heated by an immersion heater and circulates through the system by natural circulation. The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.3 (continued)

24

The ~~18~~ 2 month Frequency of the Surveillance is based on engineering judgement, taking into consideration the desired unit conditions to perform the Surveillance. Operating experience has shown that these components usually pass the SR when performed at the ~~18~~ 2 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.8.4.4 and SR 3.8.4.5

Visual inspection and resistance measurements of inter-cell, inter-rack, inter-tier, and terminal connections provides an indication of physical damage or abnormal deterioration that could indicate degraded battery condition. The anti-corrosion material is used to ensure good electrical connections and to reduce terminal deterioration. The visual inspection for corrosion is not intended to require removal of and inspection under each terminal connection.

The removal of visible corrosion is a preventive maintenance SR. The presence of visible corrosion does not necessarily represent a failure of this SR, provided visible corrosion is removed during performance of this Surveillance.

24

The ~~18~~ 2 month Frequency of the Surveillance is based on engineering judgement, taking into consideration the desired unit conditions to perform the Surveillance. Operating experience has shown that these components usually pass the SR when performed at the ~~18~~ month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.8.4.6

Battery charger capability requirements are based on the design capacity of the chargers (Ref. 4). According to Regulatory Guide 1.32 (Ref. 9), the battery charger supply is required to be based on the largest combined demands of the various steady state loads and the charging capacity to restore the battery from the design minimum charge state to

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.6 (continued)

the fully charged state, irrespective of the status of the unit during these demand occurrences. The minimum required amperes and duration ensure that these requirements can be satisfied. Momentary transients that are not attributable to charger performance do not invalidate this test.

The Surveillance Frequency is acceptable, given the unit conditions required to perform the test and the other administrative controls existing to ensure adequate charger performance during these ~~18~~ month intervals. In addition, this Frequency is intended to be consistent with expected fuel cycle lengths.

SR 3.8.4.7

A battery service test is a special test of the battery's capability, as found, to satisfy the design requirements (battery duty cycle) of the DC electrical power system. The discharge rate and test length correspond to the design duty cycle requirements as specified in Reference 4.

24

The Surveillance Frequency ~~of 18~~ months is consistent with the recommendations of Regulatory Guide 1.32 (Ref. 9) and Regulatory Guide 1.129 (Ref. 10), which state that the battery service test should be performed ~~during refueling~~ operations or at some other outage, with intervals between tests not ~~to exceed 18~~ months.

This SR is modified by two Notes. Note 1 allows the once per 60 months performance of SR 3.8.4.8 in lieu of SR 3.8.4.7. This substitution is acceptable because the battery performance test (SR 3.8.4.8) represents a more severe test of battery capacity than the battery service test (SR 3.8.4.7). Because both the battery service test and the battery performance test involve battery capacity determination, complete battery replacement invalidates the previous performance of these surveillance requirements. In addition to requiring the re-performance of both of these surveillance tests prior to declaring the battery OPERABLE, complete battery replacement also resets the 60 month time period used for substitution of the service test by the performance test. For this reason, substitution is acceptable for performance testing conducted within the first two years of service of a new battery as required by Reference 8. The reason for Note 2 is that performing the Surveillance would remove a required DC electrical power subsystem from service, perturb the electrical distribution system, and challenge safety systems. The Division III test may be performed in Mode 1, 2, or 3 in conjunction with HPCS system outages. Credit may be taken for unplanned events that satisfy the Surveillance. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

(continued)

Attachment 4
RBG-46932

List of Commitments

The following table identifies those actions committed to by Entergy in this document. Any other statements in this submittal are provided for information purposes and are not to be considered commitments.

Commitment	Due Date/Event
1) RBS setpoint calculations, and affected calibration and functional test procedures, have been revised, or will be revised prior to implementation to reflect the new 30-month drift values.	Upon implementation of the License Amendment
2) The weight of the Boron-10 contained in the SLC tank minimum required available solution volume will be increased from 143 lbm to 170 lbm to ensure adequate margin for future core designs.	Upon implementation of the License Amendment
3) RBS will initiate a change to offsite power requirements to ensure that grid voltage is no lower than 97.5% per unit, up from the current limit of 95% per unit. This change will result in an increase in minimum grid voltage operability limit from 95% per unit to 97.5% per unit and a new MCR alarm set point for Low Grid Voltage of 98.2%, up from 98%.	Upon implementation of the License Amendment
4) Instruments with TS calibration surveillance frequencies extended to 24 months will be monitored and trended. As-found and as-left calibration data will be recorded for each 24 month calibration activity for a period of three cycles.	Upon implementation of the License Amendment
5) Additionally, upon approval of this amendment request, commitments outlined in the River Bend USAR related to RG 1.32, "Criteria for Safety-Related Electric Power Systems for Nuclear Power Plants," RG 1.129, "Maintenance, Testing, and Replacement of Large Lead Storage Batteries for Nuclear Power Plants," and to IEEE-450, "Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications," to perform the battery service test (i.e., SR 3.8.4.3) during refueling outages, or at some other outage, with intervals between tests "not to exceed 18 months," will be revised to reflect intervals between tests "not to exceed 30 months."	Upon implementation of the License Amendment
Since the current plant setpoints for both of these [degraded voltage] functions will not be conservative for this change, the new calculated nominal trip setpoints will be revised in the Technical Requirements Manual.	Upon implementation of the License Amendment

Commitment	Due Date/Event
The following information will be added for the Loss of Power degraded volage function: "There is a plant-specific program which verifies that this instrument channel functions as required by verifying the As-Left and As-Found settings are consistent with those established by the setpoint methodology."	Upon implementation of the License Amendment

Attachment 5
RBG-46932

Detailed Evaluation Results

1. BACKGROUND

Technical Specification (TS) Surveillance Requirement (SR) frequency changes are required to accommodate a 24-month fuel cycle for River Bend. The proposed changes associated with this submittal were evaluated in accordance with the guidance provided in NRC Generic Letter (GL) 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24-Month Fuel Cycle," dated April 2, 1991. GL 91-04 provides NRC Staff guidance that identifies the types of information that must be addressed when proposing extensions of TS SR frequency intervals from 18 months to 24 months.

Historical surveillance test data and associated maintenance records were reviewed in evaluating the effect of these changes on safety. In addition, the licensing basis was reviewed to ensure it was not invalidated. Based on the results of these reviews, it is concluded that there is no adverse effect on plant safety due to increasing the surveillance test intervals from 18 to 24 months with the continued application of the SR 3.0.2 25% grace period.

GL 91-04 addressed steam generator inspections, which are not applicable to River Bend and therefore are not discussed in this submittal. Additionally, the GL addressed interval extensions to leak rate testing pursuant to 10 CFR Part 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors," which is also not addressed by the River Bend submittal because individual leak testing requirements have been replaced by the Primary Containment Leakage Rate Testing Program.

2. EVALUATION

In GL 91-04, the NRC provided generic guidance for evaluating a 24 month surveillance test interval for TS SRs. Attachment 1 of this submittal defines each step outlined by the NRC in GL 91-04 and provides a description of the methodology used by River Bend to complete the evaluation for each specific TS SR line item. The methodology utilized in the RBS drift analysis is similar to the methodology used for previous plant submittals such as the Perry Nuclear Power Plant, and for E.I. Hatch Nuclear Plant submittals. There have been minor revisions incorporated into the River Bend drift design guide based on NRC comments or Requests for Additional Information from previous 24-Month Fuel Cycle Extension submittals, such as RBS added the requirement that 30 samples were generally required to produce a statistically significant sample set.

For each of the identified surveillances, an effort was made to retrieve the five most recent surveillance test performances through the Spring 2008 refueling outage (i.e., approximately seven years of history). This provided approximately three 30-month surveillance periods of data to identify any repetitive problems. It has been concluded, based on engineering judgment, that three 30 month periods provide adequate performance test history. In some instances, additional surveillance performances were included when insufficient data was available for adequate statistical analysis of instrument drift. Further references to performance history reflect evaluations of the five most recent performances available through the Spring 2008 outage, unless otherwise stated.

In addition to evaluating the historical drift associated with current 18-month calibrations, the failure history of each 18-month surveillance was also evaluated. With the extension of the testing frequency to 24 months, there will be a longer period between each surveillance performance. If a failure that results in the loss of the associated safety function should occur during the operating cycle, that would only be detected by the performance of the 18-month TS SR, then the increase in the surveillance testing interval might result in a decrease in the associated function's availability. Furthermore, potential common failures of similar components tested by different surveillances were also evaluated. This additional evaluation determined whether there is evidence of repetitive failures among similar plant components.

The surveillance failures detailed with each SR exclude failures that:
(a) Did not impact a TS safety function or TS operability;
(b) Are detectable by required testing performed more frequently than the 18 month surveillance being extended; or
(c) Where the cause can be attributed to an associated event such as a preventative maintenance task, human error, previous modification or previously existing design deficiency, or that were subsequently re-performed successfully with no intervening corrective maintenance (e.g., plant conditions or malfunctioning measurement and test equipment (M&TE) may have caused aborting the test performance).

These categories of failures are not related to potential unavailability due to testing interval extension, and are therefore not listed or further evaluated in this submittal.

The following sections summarize the results of the failure history evaluation. The evaluation confirmed that the impact on system availability, if any, would be small as a result of the change to a 24-month testing frequency.

The proposed TS changes related to GL 91-04 test interval extensions have been divided into two categories. The categories are: (A) changes to surveillances other than channel calibrations, identified as "Non-Calibration Changes" and (B) changes involving the channel calibration frequency identified as "Channel Calibration Changes."

A. Non-Calibration Changes

For the non-calibration 18-month surveillances, GL 91-04 requires the following information to support conversion to a 24-month frequency:

1) Licensees should evaluate the effect on safety of the change in surveillance intervals to accommodate a 24-month fuel cycle. This evaluation should support a conclusion that the effect on safety is small.
2) Licensees should confirm that historical maintenance and surveillance data do not invalidate this conclusion.
3) Licensees should confirm that the performance of surveillances at the bounding surveillance interval limit provided to accommodate a 24-month fuel cycle would not invalidate any assumption in the plant licensing basis.

In consideration of these confirmations, GL 91-04 provides that licensees need not quantify the effect of the change in surveillance intervals on the availability of individual systems or components.

The following non-calibration TS SRs are proposed for revision to a 24-month frequency. The associated qualitative evaluation is provided for each of these changes, which concludes that the effect on plant safety is small, that the change does not invalidate any assumption in the plant licensing basis, and that the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. These conclusions have been validated by a review of the surveillance test history at River Bend as summarized below for each SR.

TS 3.1.7 Standby Liquid Control (SLC) System

SR 3.1.7.8 Verify flow through one SLC subsystem from pump into reactor pressure vessel.

The surveillance test interval of this SR is being increased from once every 18 months to once every 24 months, for a maximum interval of 30 months including the 25% grace period. The flow path through one SLC subsystem is verified per SR 3.1.7.8 during every refueling outage on a staggered test basis. This test could inadvertently cause a reactor transient if performed with the unit operating. Therefore, to decrease the potential impact of the test, it is performed during outage conditions.

The SLC system is designed so that all active components are redundant so that no single failure in one of these components would cause or prevent initiation of the SLC system. The SLC pumps are tested in accordance with the In-service Testing Program per SR 3.1.7.7 to verify operability. Similarly, the temperature of the sodium pentaborate solution in the storage tank and the temperature of the pump suction piping are verified to be ≥ 45°F every 24 hours in accordance with SR 3.1.7.2 to preclude precipitation of the boron solution. The equipment and tank containing the solution are installed in a room in which the air temperature is maintained within the range of 70°F to 100°F. Additionally an installed backup heater (automatically controlled) is used to maintain solution temperature above the saturation point (39°F to 32°F). In addition, SR 3.1.7.4 verifies the continuity of the charge in the explosive valves. These more frequent tests ensure that the SLC system remains operable during the operating cycle. Based on the inherent system and component reliability and the testing performed during the operating cycle, the impact, if any, from this change on system availability is small.

A review of the surveillance history verified that this subsystem had no previous failures of the TS functions that would have been detected solely by the periodic performance of these SRs. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on the subsystem checks required by the other TS surveillances and the history of the subsystem failures, the impact of this change on safety, if any, is small.

TS 3.1.8 Scram Discharge Volume (SDV) Vent and Drain Valves

SR 3.1.8.3 Verify each SDV vent and drain valve:

a. Closes in ≤ 30 seconds after receipt of an actual or simulated scram signal; and
b. Opens when the actual or simulated scram signal is reset

The surveillance test interval of this SR is being increased from once every 18 months to once every 24 months, for a maximum interval of 30 months including the 25% grace period. This SR ensures that the SDV vent and drain valves close in ≤ 30 seconds after receipt of an actual or simulated scram signal and open when the actual or simulated scram signal is reset. SR 3.1.8.2 requires that the SDV vent and drain valves be cycled fully closed and fully open every 92 days during the operating cycle, which ensures that the mechanical components and a portion of the valve logic remain operable. Additionally, it has been previously accepted that the failure rate of components is dominated by the mechanical components, not by the logic systems (refer to specific discussion in the Logic System Functional Test (LSFT) section below).

A review of the applicable River Bend surveillance history demonstrated that the logic subsystem for the scram discharge volume vent and drain valves had no previous failures of the TS function that would have been detected solely by the periodic performance of this SR. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on the manual cycling of the valves to ensure that the valves are operable, as required by SR 3.1.8.2, and the history of logic subsystem performance, the impact of this change on safety, if any, is small.

<u>3.3.1.1 Reactor Protection System (RPS) Instrumentation</u>

SR 3.3.1.1.14 Verify the APRM Flow Biased Simulated Thermal Power-High time constant is within the limits specified in the COLR.

The surveillance test interval of this SR is being increased from once every 18 months to once every 24 months, for a maximum interval of 30 months including the 25% grace period. The Average Power Range Monitor (APRM) Flow Biased Simulated Thermal Power-High function uses an electronic filter circuit to generate a signal proportional to the core thermal power from the APRM neutron flux signal. Operation of the circuits associated with this trip function are verified more frequently by Channel Check (i.e., SR 3.3.1.1.1), verification of the absolute difference between APRM channels (i.e., SR 3.3.1.1.2), verification of the flow signal (i.e., SR 3.3.1.1.3), Channel Functional Test (i.e., SR 3.3.1.1.9), and Channel Calibration (i.e., SR 3.3.1.1.11). This testing ensures that a significant portion of the circuitry is operating properly and will detect significant failures of this circuitry.

A review of the surveillance history demonstrated that this circuit had no previous failures of the TS function that would have been detected solely by the periodic performance of this SR. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on the checks required by the other TS surveillances and the history of the circuit failures, the impact of this change on safety, if any, is small.

<u>LOGIC SYSTEM FUNCTIONAL TESTS (LSFTs) and SELECTED CHANNEL FUNCTIONAL TESTS</u>

<u>3.3.1.1 Reactor Protection System (RPS) Instrumentation</u>

SR 3.3.1.1.12 Perform CHANNEL FUNCTIONAL TEST.

(This test is essentially a Logic System Functional Test for the Reactor Mode Switch scram circuit. The justification for extending LSFTs is also valid for the extension of this SR.)

SR 3.3.1.1.15 Perform LOGIC SYSTEM FUNCTIONAL TEST.

3.3.2.1 Control Rod Block Instrumentation

SR 3.3.2.1.8 Perform CHANNEL FUNCTIONAL TEST.

(This test is essentially a Logic System Functional Test for the Reactor Mode Switch rod block circuit. The justification for extending LSFTs is also valid for the extension of this SR.)

3.3.3.2 Remote Shutdown System

SR 3.3.3.2.2 Verify each required control circuit and transfer switch is capable of performing the intended functions.

(This test is essentially a Logic System Functional Test for the transfer circuits associated with shifting indication and control from the control room to the remote shutdown panel. The justification for extending LSFTs is also valid for the extension of this SR.)

3.3.4.1 End of Cycle Recirculation Pump Trip (EOC-RPT) Instrumentation

SR 3.3.4.1.4 Perform LOGIC SYSTEM FUNCTIONAL TEST, including breaker actuation.

3.3.4.2 Anticipated Transient Without Scram Recirculation Pump Trip (ATWS-RPT) Instrumentation

SR 3.3.4.2.5 Perform LOGIC SYSTEM FUNCTIONAL TEST, including breaker actuation.

3.3.5.1 Emergency Core Cooling System (ECCS) Instrumentation

SR 3.3.5.1.6 Perform LOGIC SYSTEM FUNCTIONAL TEST.

3.3.5.2 Reactor Core Isolation Cooling (RCIC) System Instrumentation

SR 3.3.5.2.5 Perform LOGIC SYSTEM FUNCTIONAL TEST.

3.3.6.1 Primary Containment and Drywell Isolation Instrumentation

SR 3.3.6.1.6 Perform LOGIC SYSTEM FUNCTIONAL TEST.

3.3.6.2 Secondary Containment and Fuel Building Isolation Instrumentation

SR 3.3.6.2.5 Perform LOGIC SYSTEM FUNCTIONAL TEST.

3.3.6.3 Containment Unit Cooler System Instrumentation

SR 3.3.6.3.5 Perform LOGIC SYSTEM FUNCTIONAL TEST.

3.3.6.4 Relief and Low-Low Set (LLS) Instrumentation

SR 3.3.6.4.4 Perform LOGIC SYSTEM FUNCTIONAL TEST.

3.3.7.1 Control Room Fresh Air (CRFA) System Instrumentation

SR 3.3.7.1.5 Perform LOGIC SYSTEM FUNCTIONAL TEST.

3.3.8.1 Loss of Power (LOP) Instrumentation

SR 3.3.8.1.4 Perform LOGIC SYSTEM FUNCTIONAL TEST.

<u>3.3.8.2 Reactor Protection System (RPS) Electric Power Monitoring</u>

SR 3.3.8.2.3 Perform a system functional test.

(*This test is essentially a Logic System Functional Test for the RPS Electric Power Monitor circuits. The justification for extending LSFTs is also valid for this SR.*)

The surveillance test interval of these SRs is being increased from once every 18 months to once every 24 months, for a maximum interval of 30 months including the 25% grace period. Extending the surveillance test interval for the LSFTs and selected functional tests is acceptable because the functions are verified to be operating properly by the performance of more frequent Channel Checks, Channel Functional Tests, analog trip module calibration, and visual confirmation of satisfactory operation (as applicable). This more frequent testing ensures that a major portion of the circuitry is operating properly and will detect significant failures within the instrument loop. Additionally, all of the above actuation instrumentation and logic, controls, monitoring capabilities, and protection systems, are designed to meet applicable reliability, redundancy, single failure, and qualification standards and regulations as described in the River Bend Updated Safety Analysis Report (USAR). As such, these functions are designed to be highly reliable. Furthermore, as stated in the August 2, 1993 NRC Safety Evaluation Report relating to extension of the Peach Bottom Atomic Power Station, Unit Numbers 2 and 3 surveillance intervals from 18 to 24 months:

> "Industry reliability studies for boiling water reactors (BWRs), prepared by the BWR Owners Group (NEDC-30936P) show that the overall safety systems' reliabilities are not dominated by the reliabilities of the logic systems, but by that of the mechanical components, (e.g., pumps and valves), which are consequently tested on a more frequent basis. Since the probability of a relay or contact failure is small relative to the probability of mechanical component failure, increasing the Logic System Functional Test interval represents no significant change in the overall safety system unavailability."

A review of the applicable River Bend surveillance history demonstrated that the logic systems for these functions had only five failures of the TS functions that would have been detected solely by the periodic performance of one of the above SRs.

a) On February 14, 2006, relay B21C-K30A (SR 3.3.6.4.4-a) failed and was replaced with new Agastat EGPD004 relay. Troubleshooting indicated the relay had an open coil. The identified failure is unique and does not occur on a repetitive basis and is not associated with a time-based failure mechanism.

b) On January 2, 2007 the MSIVs did not isolate as expected. Troubleshooting determined that relays B21H-K7F and B21H-K14B (SR 3.3.6.1.6-1.d) failed. Work Orders replaced the relays with P&B MDR-4172 and Agastat EGPI004 relays respectively and retest was performed satisfactorily. The identified failure is unique and does not occur on a repetitive basis and is not associated with a time-based failure mechanism.

c) On November 28, 2002, relay E31A-K4A (SR 3.3.6.1.6, Functions 3.h and 5.a) failed to change state. The relay was replaced with a new Agastat EGPI004 relay and was retested satisfactorily. The identified failure is unique and does not occur on a repetitive basis and is not associated with a time-based failure mechanism.

d) On June 24,1999 valve E51-MOVF076 failed to isolate on a DIV 2 simulated low pressure isolation signal in a test procedure Technical Specification required step.(SRs 3.3.6.1.6-3.a, 3.b, 3.c, 3.d, 3.e, 3.f, 3.g, and 3.i). Troubleshooting/repair determined that a control power fuse was blown and that the reversing contactor coil was bad (low ohms). The coil and fuse were replaced. The valve was satisfactorily stroke timed. Retesting was also performed satisfactorily. Investigation determined that this was a functional failure of the containment isolation valve. The identified failure is unique and does not occur on a repetitive basis and is not associated with a time-based failure mechanism.

e) On March 13, 2000, HVC-FN3C breaker tripped(SR 3.3.3.2.2). Troubleshooting determined that the problem was a defective breaker. The breaker had what is referred to as a "weak" phase. One phase of the breaker would trip at a lower current than the other two phases. The breaker was replaced with a new GE/TEC36007 Molded Case Circuit Breaker and retested satisfactorily. During the retest the breaker operated as designed. The identified failure is unique and does not occur on a repetitive basis and is not associated with a time-based failure mechanism.

In regards to the February 14, 2006, January 2, 2007, and November 28, 2002 events, a commonality review was performed on Agastat and Potter & Brumfield relay failures. There are a total of eight Agastat relay failures and two Potter and Brumfield relay failures identified over the review period. Of the eight Agastat relay failures, four failures were Model EGPI, was Model ETR14D3N and two were Model ETR14D3G. In all eight Agastat relay failures, the defective relays were replaced. Two of the Agastat Model EGPI failures were in the RHR Equipment Room Ambient Temperature function of the Primary Containment Isolation logic in 2002 and the Main Steam Line Isolation function of the Primary Containment Isolation Logic circuitry in 2007. One of the Agastat Model EGPI failures occurred in 2003 and was in the Compressor C3A Seal Makeup Isolation Valve auto closure circuit and the fourth Agastat EGPI failure occurred in 2008 and was in the DIV I EDG Trip Logic. The Agastat Model ETR14D3N relay failure occurred in 1999 and the relay is utilized in the Containment Unit Cooler System. One Agastat Model ETR14D3G relay failure occurred in 1999 and was in Chiller HVK-CHL1A load sequencing circuit and the second Agastat Model ETR14D3G relay failure occurred in 2000 and was in Chiller HVK-CHL1C load sequencing circuit. Of the two Potter and Brumfield relay failures, one failure was a Model MDR-4171 and one was a model MDR-4172. In both of the Potter and Brumfield relay failures, the defective relays were replaced. One of the relay failures occurred in 2007 and is part of the Main Steam Line Isolation on Condenser Low Vacuum function of the Primary Containment Isolation and the second failure occurred in 2006 and is in the Div IV RPS Trip Logic "D" and initiates an MSL Drain Valve Isolation signal in RPS/ESF Div I. For several of the historical failures, detailed evaluation indicated that the relays were not in the plant programs due to an oversight in assigning identification numbers to skid mounted equipment subcomponents. This oversight resulted in some relays being left in service past their required service replacement dates, with resulting relay failures. The plant subsequently evaluated all skid mounted equipment to ensure that the subcomponents were identified and included in the preventative maintenance program. This activity resulted in the upgrading of a number of relays. There are no time-based mechanisms apparent in these failures. Therefore, each of these failures is unique and any subsequent failure would not result in a significant impact on system/component availability.

In regards to the June 24, 1999 and March 13, 2000 events, no similar failures are identified; therefore, the failures were not repetitive in nature. No time based mechanisms are apparent. Therefore, these failures are unique and any subsequent failures would not result in a significant impact on system/component availability.

As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on other more frequent testing of portions of the circuits, and the history of logic system performance, and the corrective action for relay failures the impact of this change on safety, if any, is small.

<u>RESPONSE TIME TESTS</u>

<u>3.3.1.1 Reactor Protection System (RPS) Instrumentation</u>
SR 3.3.1.1.18 Verify the RPS RESPONSE TIME is within limits.

<u>3.3.4.1 End of Cycle Recirculation Pump Trip (EOC-RPT) Instrumentation</u>
SR 3.3.4.1.6 Verify the EOC-RPT SYSTEM RESPONSE TIME is within limits.

<u>3.3.6.1 Primary Containment and Drywell Isolation Instrumentation</u>
SR 3.3.6.1.7 Verify the ISOLATION SYSTEM RESPONSE TIME for the Main Steam Isolation Valves is within limits.

The "on a staggered test basis" surveillance test interval of these SRs is being increased from once every 18 months to once every 24 months, for a maximum interval of 30 months including the 25% grace period. Extending the interval between response time tests is acceptable because the functions are verified to be operating properly throughout the operating cycle by the performance of Channel Checks and Channel Functional Tests (as applicable). This testing ensures that a significant portion of the circuitry is operating properly and will detect significant failures of this circuitry. Additional justification for extending the surveillance test interval is that these functions, including the actuating logic, are designed to be single failure proof and, therefore, are highly reliable.

Furthermore, the River Bend TS Bases (as well as the Improved Standard TS, NUREG-1434) states that the frequency of response time testing is based in part "upon plant operating experience, which shows that random failures of instrumentation components causing serious time degradation, but not channel failure, are infrequent."

A review of the applicable River Bend surveillance history demonstrated that the logic systems for these functions had no previous failures of TS required system response times that would have been detected solely by the periodic performance of these SRs. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on other more frequent testing of portions of the circuits, and the history of logic system performance, the impact of this change on safety, if any, is small.

3.4.2 Flow Control Valves (FCVs)

SR 3.4.2.1 Verify each FCV fails "as is" on loss of hydraulic pressure at the hydraulic unit.
SR 3.4.2.2 Verify average rate of each FCV movement is:

a. ≤ 11% of stroke per second for opening; and
b. ≤ 11% of stroke per second for closing.

The surveillance test interval of these SRs is being increased from once every 18 months to once every 24 months, for a maximum interval of 30 months including the 25% grace period. For SR 3.4.2.1, the hydraulic power unit pilot operated lock out valves (i.e., pilot operated check valves) are required to close on a loss of recirculation FCV hydraulic pressure. When closed, these valves inhibit FCV motion and preclude potentially excessive rate-of-change in reactor power from uncontrolled recirculation FCV movement. This surveillance verifies the FCV fails "as-is" on a loss of hydraulic pressure. Due to the nature of the check valve function in this application, there are no definable drift components or any time based conditions that could appreciably change during the operating cycle.

For SR 3.4.2.2, the test ensures the overall average rate of FCV movement at all positions is maintained within the analyzed limits. Due to the nature of the control components in this application, there are no definable components or any time based conditions that could appreciably change the rate of change for opening or closing the FCV during the operating cycle. The FCV actuator has an inherent rate-limiting feature that will limit the resulting rate of change of core flow and power to within safe limits in the event of an upscale or downscale failure of the valve position or velocity control system. The surveillance test interval is being increased from once every 18 months to once every 24 months, for a maximum of 30 months including the 25% grace period.

A review of the applicable River Bend surveillance history demonstrated that the hydraulic power unit pilot operated lock out valves had no previous failures of the TS function that would have been detected solely by the periodic performance of this SR. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on the reliability of the check valves and history of system performance, the impact of this change on safety, if any, is small.

3.4.4 Safety/Relief Valves (S/RVs)

SR 3.4.4.2 Verify each required relief function S/RV actuates on an actual or simulated automatic initiation signal.

The surveillance test interval of SR 3.4.4.2 is being increased from once every 18 months to once every 24 months, for a maximum interval of 30 months including the 25% grace period. The relief function S/RVs are required to actuate automatically upon receipt of specific initiation signals. A system functional test (i.e., SR 3.4.4.2) is performed to verify the mechanical portions (i.e., solenoids) of the automatic relief function operate as designed when initiated either by an actual or simulated initiation signal. A manual actuation of each required S/RV (i.e., SR 3.4.4.3) is performed to verify that the valve is functioning properly. The LSFT in SR 3.3.6.4.4 overlaps this SR to provide complete testing of the safety function. Valve operability and the setpoints for overpressure protection are verified, per ASME requirements, prior to valve installation. This verification proves that the valve was actually functioning when installed and that the mechanical valve components were in good condition. The valves are normally tested prior to or soon after startup; any failure of actual valve function would be noted and corrected prior to extended plant operation.

A review of the applicable River Bend surveillance history demonstrated that the S/RVs had no previous failures of the TS functions that would have been detected solely by the periodic performance of these SRs. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on the history of system performance, the impact of this change on safety, if any, is small.

3.5.1 / 3.5.2 ECCS-Operating / ECCS-Shutdown

SR 3.5.1.5	Verify each ECCS injection/spray subsystem actuates on an actual or simulated automatic initiation signal.
SR 3.5.1.6	Verify the ADS actuates on an actual or simulated automatic initiation signal.
SR 3.5.1.8	Verify the ECCS RESPONSE TIME for each ECCS injection/spray subsystem is within limits.
SR 3.5.2.6	Verify each required ECCS injection/spray subsystem actuates on an actual or simulated automatic initiation signal.

The surveillance test interval of these SRs is being increased from once every 18 months to once every 24 months, for a maximum interval of 30 months including the 25% grace period. These ECCS and ADS functional tests ensure that a system initiation signal (actual or simulated) to the automatic initiation logic will cause the systems or subsystems to operate as designed within assumed response times. The ECCS network has built-in redundancy so that no single active failure prevents accomplishing the safety function of the ECCS. The pumps and valves associated with ECCS are tested quarterly in accordance with the In-service Testing (IST) Program and SR 3.5.1.4 (some valves may have independent IST relief justifying less frequent testing). This testing ensures that the major components of the systems are capable of performing their design function. The tests proposed to be extended need to be performed during outage conditions since they have the potential to initiate an unplanned transient if performed during operating conditions.

A review of the applicable River Bend surveillance history demonstrated that ECCS had no previous failures of the TS functions that would have been detected solely by the periodic performance of these SRs. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on other more frequent testing of the system, and the history of system performance, the impact of this change on safety, if any, is small.

3.5.3 RCIC System

SR 3.5.3.4 Verify, with RCIC steam supply pressure ≤ 165 psig and ≥ 150 psig, the RCIC pump can develop a flow rate ≥ 600 gpm against a system head corresponding to reactor pressure.

SR 3.5.3.5 Verify the RCIC System actuates on an actual or simulated automatic initiation signal.

The surveillance test interval of these SRs is being increased from once every 18 months to once every 24 months, for a maximum interval of 30 months including the 25% grace period. These RCIC functional tests ensure that the system will operate as designed. The pumps and valves associated with RCIC system are tested quarterly in accordance with the In-service Testing Program (some valves may have independent relief justifying less frequent testing). This testing ensures that the major components of the systems are capable of performing their design function.

A review of the applicable River Bend surveillance history demonstrated that RCIC had no previous failures of these TS functions that would have been detected solely by the periodic performance of these SRs. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on other more frequent testing of the system, and the history of system performance, the impact of this change on safety, if any, is small.

3.6.1.2 Primary Containment Air Locks

SR 3.6.1.2.4 Verify, from an initial pressure of 90 psig, the primary containment air lock seal pneumatic system pressure does not decay at a rate equivalent to ≥ 1.50 psig for a period of 24 hours.

The surveillance test interval of this SR is being increased from once every 18 months to once every 24 months, for a maximum interval of 30 months including the 25% grace period. This SR ensures that the primary containment air lock seal pneumatic system pressure does not decay at an unacceptable rate. System availability during the operating cycle is assured by:
The air lock seal air flask pressure is verified in SR 3.6.1.2.2 to be ≥ 90 psig every 7 days to ensure that the seal system remains viable. In addition SR 3.6.1.2.3 verifies only one door in the primary containment air lock can be opened at one time every 184 days. Closure of a single door in the air lock is necessary to support containment OPERABILITY following postulated events. Nevertheless, both doors are kept closed when the air lock is not being used for entry into and exit from the primary containment. Each door of the containment air lock has two seals to ensure that they are single-failure proof in maintaining the leak tight boundary of primary containment.

A review of the applicable River Bend surveillance history demonstrated that the drywell air lock valves had only one previous failures of the TS function that would have been detected solely by the periodic performance of this SR. On July 18, 2005 the primary containment air lock seal pneumatic system pressure decay rate failed due to leakage rate exceeded allowed values in a Technical Specification required test procedure step. A Work Order determined that the leakage was caused by leaking 1/2" ball valves. The ball valves were rebuilt with Seal Kit P/N 70060002. The leak rate test was re-performed satisfactory. The identified failure is unique and does not occur on a repetitive basis and is not associated with a time-based failure mechanism.

No similar failures are identified; therefore, the failure is not repetitive in nature. No time based mechanisms are apparent. Therefore, this failure is unique and any subsequent failures would not result in a significant impact on system/component availability. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on other more frequent testing of the system, and the history of system performance, the impact of this change on safety, if any, is small.

3.6.1.3 Primary Containment Isolation Valves (PCIVs)

SR 3.6.1.3.7 Verify each automatic PCIV actuates to the isolation position on an actual or simulated isolation signal.

SR 3.6.1.3.8 Verify in-leakage rate of ≤ 340 scfh for each of the following valve groups when tested at 11.5 psid for MS-PLCS valves.
a. Division I MS-PLCS valves
b. Division II MS-PLCS valves

The surveillance test interval of these SRs is being increased from once every 18 months to once every 24 months, for a maximum interval of 30 months including the 25% grace period. For SR 3.6.1.3.7, during the operating cycle, SR 3.6.1.3.4 requires automatic PCIV isolation times to be verified in accordance with the In-service Testing Program. Stroke testing of PCIVs tests a significant portion of the PCIV circuitry as well as the mechanical function, which will detect failures of this circuitry or failures with valve movement. The frequency of this testing is typically quarterly, unless approved relief has been granted justifying less frequent testing..

For SR 3.6.1.3.8 the Technical Specification Bases states that the use of MS-PLCS as a positive leakage barrier results in in-leakage and gradual pressure buildup within the containment. The total allowable MSIV in-leakage rate does not have radiological consequences. This surveillance ensures that the total allowable air in-leakage rate is limited such that containment pressurization does not exceed 50 percent of the design value in a 30 day period due to these sources. The Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components have not failed when performed at the 18 month Frequency. Therefore, given the history, and purpose of the Surveillance test increasing the Frequency is concluded to be acceptable from a reliability standpoint..

A review of the River Bend surveillance test history demonstrated only two previous failures of the TS function for SR 3.6.1.3.7 and none for SR 3.6.1.3.8 that would have been detected solely by the periodic performance of these SRs.

a) On June 24,1999 valve E51-MOVF076 failed to isolate on a DIV 2 simulated low pressure isolation signal in a test procedure Technical Specification required step.(SR 3.6.1.3.7) Troubleshooting/repair determined that a control power fuse was blown and that the reversing contactor coil was bad (low ohms). The coil and fuse were replaced. The valve was satisfactorily stroke timed. Retesting was also performed satisfactorily. Investigation determined that this was a functional failure of the containment isolation valve. The identified failure is unique and does not occur on a repetitive basis and is not associated with a time-based failure mechanism.

b) On May 22, 2006, Main Steam Line Drain Valves B21-F067A through D failed to stroke closed as expected during LOP/LOCA in a Technical Specification required step. Troubleshooting confirmed that relay B21H-K200D had failed. A Work Order replaced B21H-K200D with a new P&B Model MDR-4171and satisfactorily retested the relay. B21H-K200D is in DIV IV RPS Trip Logic "D". Other event driven failures were identified, listed below, that were either associated with the performance of the surveillance test steps or with equipment test setup, and have no impact on the system availability: 1) EGS-PNL3A-F5 4160 STBY BUS UNDERVOLTAGE alarm was not in an alarm state in a non-Technical Specification test procedure step. Investigation determined that these test procedure steps were inadvertently left in the procedure due to past failed equipment. A Work Order verified correct operation of BUS UNDERVOLTAGE alarm using ERIS. 2) Chiller HVK-CHL1A failed to load sequence within the required time of 180.9 to 221.1 seconds per a Technical Specification required step. Load Sequence time was 239.1 seconds (ERIS). An investigation determined that the Chiller HVKCHL1A failed to load sequence within the required TS time due to an Operator error -Operations had failed to LOCKOUT chill water pumps for Division II; this caused a delay in HVK-CHL1A start time of 30 seconds. A Work Order performed satisfactory retest of HVK-CHL1A sequence time at 194.3 seconds. The identified failure is unique and does not occur on a repetitive basis and is not associated with a time-based failure mechanism.

In regards to the June 24, 1999 event, no similar failures are identified; therefore, the failure is not repetitive in nature. No time based mechanisms are apparent. Therefore, this failure is unique and any subsequent failures would not result in a significant impact on system/component availability. In regards to the May 22, 2006 event, there are a total of two Potter and Brumfield relay failures identified over the review period. Of the two Potter and Brumfield relay failures, one failure was a Model MDR-4171 and one was a model MDR-4172. In both of the Potter and Brumfield relay failures, the defective relays were replaced. One of the relay failures occurred in 2007 and is part of the Main Steam Line Isolation on Condenser Low Vacuum function of the Primary Containment Isolation and the second failure occurred in 2006 and is in the Div IV RPS Trip Logic "D" and initiates an MSL Drain Valve Isolation signal in RPS/ESF Div I. There are no time-based mechanisms apparent in these failures. Therefore, this failure is unique and any subsequent failure would not result in a significant impact on system/component availability.

As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on the history of system performance, the impact of this change on safety, if any, is small for both Surveillance Requirements.

3.6.1.6 Low-Low Set (LLS) Valves

SR 3.6.1.6.2 Verify the LLS System actuates on an actual or simulated automatic initiation signal.

The surveillance test interval of these SRs is being increased from once every 18 months to once every 24 months, for a maximum interval of 30 months including the 25% grace period. Extending the surveillance test interval for these functional tests is acceptable because the functions are verified to be operating properly by the performance of more frequent Channel Functional Tests (i.e., SR 3.3.6.4.1) and analog trip module calibrations (i.e., SR 3.3.6.4.2). This more frequent testing ensures that a major portion of the circuitry is operating properly and will detect significant failures within the instrument loop. Additionally, the LLS valves (i.e., safety/relief valves assigned to the LLS logic) are designed to meet applicable reliability, redundancy, single failure, and qualification standards and regulations as described in the River Bend USAR. As such, these functions are designed to be highly reliable.

A review of surveillance test history verified that the LLS valves had no previous failures of the TS functions that would have been detected solely by the periodic performance of these SRs. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on other more frequent testing of the system, system design, and the history of system performance, the impact of this change on safety, if any, is small.

3.6.1.7 Primary Containment Unit Coolers

SR 3.6.1.7.3 Verify each required primary containment unit cooler actuates throughout its emergency operating sequence on an actual or simulated automatic initiation signal.

The surveillance test interval of this SR is being increased from once every 18 months to once every 24 months, for a maximum interval of 30 months including the 25% grace period. The Primary Containment Unit Coolers have built-in redundancy so that no single active failure prevents the ability to maintain primary containment pressure and temperature within design limits following a LOCA with maximum allowable bypass leakage. SR 3.6.1.7.2 verifies that each of the primary containment unit coolers develops proper flow rates on a quarterly basis. Additionally, SR 3.3.6.3.2 (CHANNEL FUNCTIONAL TEST) and SR 3.3.6.3.3 (Calibrate the trip unit) perform testing of the actuation instrumentation. These tests ensure that the major components of the systems are capable of performing their design function. Since most of the components and associated circuits are tested on a more frequent basis, this testing would indicate any degradation to the Primary Containment Unit Coolers which would result in an inability to start based on a demand signal.

Furthermore, a review of the applicable River Bend surveillance history demonstrated that the Primary Containment Unit Coolers had no previous failures of the TS function that would have been detected solely by the periodic performance of this SR. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on other more frequent testing of the system, system design, and the history of system performance, the impact of this change on safety, if any, is small.

3.6.1.9 Main Steam-Positive Leakage Control System (MS-PLCS)

SR 3.6.1.9.3 Perform a system functional test of each MS-PLCS subsystem.

The surveillance test interval of this SR is being increased from once every 18 months to once every 24 months, for a maximum interval of 30 months including the 25% grace period. A system functional test is performed to ensure that the MS-PLCS will operate through its operating sequence.

SR 3.6.1.9.2 operates each PVLCS compressor every 31 days. This more frequent testing ensures that the major components of the systems are capable of performing their design function. Since the major components of this manually initiated system are tested on a more frequent basis, this testing would indicate any degradation to the MS-PLCS. Additionally, the MS-PLCS subsystems are designed to perform the safety function in the event of any single active failure, and therefore, are highly reliable.

A review of the applicable River Bend surveillance history demonstrated that the MS-PLCS had no previous failure of the TS function that would have been detected solely by the periodic performance of this SR.As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on other more frequent testing of the system, system design, and the history of system performance, the impact of this change on safety, if any, is small.

3.6.3.2 Primary Containment and Drywell Hydrogen Igniters

SR 3.6.3.2.3 Verify each required igniter in inaccessible areas develops sufficient current draw for a ≥ 1700°F surface temperature.
SR 3.6.3.2.4 Verify each required igniter in accessible areas develops a surface temperature of ≥ 1700°F.

The surveillance test interval of these SRs is being increased from once every 18 months to once every 24 months, for a maximum interval of 30 months including the 25% grace period. The igniters are mechanically passive and are not subject to mechanical failure. Extending the surveillance test interval for these tests is acceptable because the functions are verified to be operating properly by the performance of more frequent current versus voltage measurements every 184 days or 92 days per SR 3.6.3.2.1 or SR 3.6.3.2.2, respectively. These SRs verify there are no physical problems that could affect the igniter operation. The only credible failures are loss of power or burnout. The verification that each required igniter is energized is performed by circuit current versus voltage measurement.

A review of the applicable River Bend surveillance history demonstrated that the Hydrogen Igniter System had four previous failures of the TS functions that would have been detected solely by the periodic performance of these SRs.

a) On March 25, 2003, igniter HCS-IGN04A found failed. The igniter was replaced. The identified failure is unique and does not occur on a repetitive basis and is not associated with a time-based failure mechanism.

b) On November 15, 2004 igniter HCS-IGN01A failed. A work order was initiated for repairs. The identified failure is unique and does not occur on a repetitive basis and is not associated with a time-based failure mechanism.

c) On May 8, 2006 igniters HCS-IGN01A, 05A, and 07A failed. Work orders were written to replace. The identified failure is unique and does not occur on a repetitive basis and is not associated with a time-based failure mechanism.

d) On February 24, 2008 igniters HCS-IGN08B, HCS-IGN23A, HCS-IGN34B discovered failed during STP test. Work orders were initiated to repair/replace. The identified failure is unique and does not occur on a repetitive basis and is not associated with a time-based failure mechanism.

There are a total of nine surveillance procedure performances containing a total of eight hydrogen igniter failures over the review period; the eight failures occurred within four of the nine procedures reviewed. The surveillance procedure tests both Division 1 and Division 2 primary containment and hydrogen igniters via verification that accessible igniters reach the required surface temperature and that inaccessible igniters develop sufficient current draw for the required surface temperature. Each performance of the surveillance procedure tests 104 igniters. Eight igniter failures within nine surveillance performances over the review period represent a very small percentage of the total possible igniter failures. There are no time-based mechanisms apparent since there were three igniter failures in 2008, three failures in 2006, and one failure in 2004. One igniter did fail in both 2004 and 2006; however, there is no history of that same igniter failing prior to 2004 or after 2006. Based on the fact that the hydrogen igniter failures are not time based, this failure is unique and any subsequent failure would not result in a significant impact on system/component availability. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on other more frequent testing of the system, and the history of system performance, the impact of this change on safety, if any, is small.

<u>3.6.3.3 Containment/Drywell Hydrogen Mixing System</u>

SR 3.6.3.3.2 Verify each containment/drywell hydrogen mixing system flow rate is $\geq$ 600 cfm.

The surveillance test interval of this SR is being increased from once every 18 months to once every 24 months, for a maximum interval of 30 months including the 25% grace period. SR 3.6.3.3.2 requires verification of each subsystem's flow rate. However, SR 3.6.3.3.1 ensures that each system is operable and that all associated controls are functioning properly on a more frequent basis (i.e., Every COLD SHUTDOWN, if not performed within the previous 92 days). SR 3.6.3.3.1 also ensures that blockage, compressor failure, or excessive vibration can be detected for corrective action. While SR 3.6.3.3.1 does not verify that system flow rate is acceptable, the test would indicate significant system problems or failures. Furthermore, the containment/drywell hydrogen mixing system has built-in redundancy so that no single-failure prevents system operation.

A review of the applicable River Bend surveillance history demonstrated that the Containment/Drywell Hydrogen Mixing System had no previous failures of the TS function that would have been detected solely by the periodic performance of this SR. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on other more frequent testing of the system, system design, and the history of system performance, the impact of this change on safety, if any, is small.

<u>3.6.4.1 Secondary Containment-Operating</u>

SR 3.6.4.1.4 Verify each standby gas treatment (SGT) subsystem will draw down the shield building annulus and auxiliary building to ≥ 0.5 and ≥ 0.25 inch of vacuum water gauge in ≤ 18.5 and ≤ 34.5 seconds, respectively.

SR 3.6.4.1.6 Verify each SGT subsystem can maintain ≥0.5 and ≥ 0.25 inch of vacuum water gauge in the shield building annulus and auxiliary building, respectively, for 1 hour.

The surveillance test interval of these SRs is being increased from once every 18 months to once every 24 months, for a maximum interval of 30 months including the 25% grace period. To ensure that all fission products are treated, the tests required per SR 3.6.4.1.4 and SR 3.6.4.1.6 are performed utilizing one SGT subsystem (on a staggered test basis) to ensure secondary containment boundary integrity. SRs 3.6.4.1.1 (every 24 hours), 3.6.4.1.2 (every 31 days), and 3.6.4.1.3 (every 31 days) provide more frequent assurance that no significant boundary degradation has occurred.

A review of the applicable River Bend surveillance history demonstrated that the secondary containment had no previous failure of the TS functions that would have been detected solely by the periodic performance of these SRs. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on other more frequent testing of the system, and the history of system performance, the impact of this change on safety, if any, is small.

<u>3.6.4.2 Secondary Containment Isolation Dampers (SCIDs) and Fuel Building Isolation Dampers (FBIDs)</u>

SR 3.6.4.2.2 Verify each required automatic SCID and FBID actuates to the isolation position on an actual or simulated automatic isolation signal.

The surveillance test interval of this SR is being increased from once every 18 months to once every 24 months, for a maximum interval of 30 months including the 25% grace period. During the operating cycle, SR 3.6.4.2.1 requires that each power-operated automatic SCID and FBID isolation time be tested (i.e., stroke timed to the closed position) quarterly. The stroke testing of these SCIDs tests a portion of the circuitry and the mechanical function, and provides more frequent testing to detect failures.

A review of surveillance test history verified that SCIDs had no previous failures of the TS function that would have been detected solely by the periodic performance of this SR. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on other more frequent testing of the system, and the history of system performance, the impact of this change on safety, if any, is small.

3.6.4.3 Standby Gas Treatment (SGT) System

SR 3.6.4.3.3 Verify each SGT subsystem actuates on an actual or simulated initiation signal.
SR 3.6.4.3.4 Verify each SGT filter cooling bypass damper can be opened and the fan started.

The surveillance test interval of these SRs is being increased from once every 18 months to once every 24 months, for a maximum interval of 30 months including the 25% grace period. These SGT functional tests ensure that subsystems operate as designed. The SGT subsystems are redundant so that no single-failure prevents accomplishing the safety function of filtering the discharge from secondary containment, and are therefore reliable. More frequent verification of portions of the SGT function are accomplished by operating each SGT subsystem and heaters every 31 days (i.e., SR 3.6.4.3.1) and by SGT filter testing required by the Ventilation Filter Testing Program (i.e., SR 3.6.4.3.2).

A review of the applicable River Bend surveillance history demonstrated that the SGT System had no previous failure of the TS functions that would have been detected solely by the periodic performance of these SRs. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on other more frequent testing of the system, system design, and the history of system performance, the impact of this change on safety, if any, is small.

3.6.4.7 Fuel Building Ventilation System-Fuel Handling

SR 3.6.4.7.4 Verify each fuel building ventilation charcoal filtration subsystem actuates on an actual or simulated initiation signal.
SR 3.6.4.7.5 Verify each fuel building ventilation charcoal filtration filter cooling bypass damper can be opened and the fan started.

The surveillance test interval of these SRs is being increased from once every 18 months to once every 24 months, for a maximum interval of 30 months including the 25% grace period. The Fuel Building Ventilation System subsystems are redundant so that no single-failure prevents accomplishing the safety function of mitigating the consequences of a fuel handling accident involving recently irradiated fuel, and are therefore reliable. During the operating cycle, SR 3.6.4.7.2 operates each fuel building ventilation charcoal filtration subsystem for ≥ 10 continuous hours with the heaters operating monthly. This test ensures that both subsystems are operable and that all associated controls are functioning properly. It also ensures that blockage, fan or motor failure, or excessive vibration can be detected.

A review of the applicable River Bend surveillance history demonstrated that the Fuel Building Ventilation System had no previous failures of the TS function that would have been detected solely by the periodic performance of this SR. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on other more frequent testing of the system, and the history of system performance, the impact of this change on safety, if any, is small.

3.6.5.1 Drywell

SR 3.6.5.1.2 Verify from an initial pressure of 75 psig, the personnel door inflatable seal pneumatic system pressure does not decay at a rate equivalent to ≥ 20.0 psig for a period of 24 hours.

The surveillance test interval of these SRs is being increased from once every 18 months to once every 24 months, for a maximum interval of 30 months including the 25% grace period. This SR ensures that the drywell air lock seal pneumatic system pressure does not decay at an unacceptable rate. The air lock seal air flask pressure is verified in SR 3.6.5.1.1 to be ≥ 75 psig every 7 days to ensure that the seal system remains viable. Closure of a single door in the air lock is necessary to support drywell OPERABILITY following postulated events. Nevertheless, both doors are kept closed when the air lock is not being used for entry into and exit from the drywell.

A review of the applicable River Bend surveillance history demonstrated that the drywell personnel door inflatable seal pneumatic system had no previous failures of the TS function that would have been detected solely by the periodic performance of this SR. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on other more frequent testing of the system, and the history of system performance, the impact of this change on safety, if any, is small

3.6.5.2 Drywell Air Lock

SR 3.6.5.2.5 Verify from an initial pressure of 75 psig, the drywell air lock seal pneumatic system pressure does not decay at a rate equivalent to ≥ 20.0 psig for a period of 24 hours.

The surveillance test interval of these SRs is being increased from once every 18 months to once every 24 months, for a maximum interval of 30 months including the 25% grace period. This SR ensures that the drywell air lock seal pneumatic system pressure does not decay at an unacceptable rate. The air lock seal air flask pressure is verified in SR 3.6.5.2.2 to be ≥ 75 psig every 7 days to ensure that the seal system remains viable. Closure of a single door in the air lock is necessary to support drywell OPERABILITY following postulated events. Nevertheless, both doors are kept closed when the air lock is not being used for entry into and exit from the drywell.

A review of the applicable River Bend surveillance history demonstrated that the drywell air lock seal pneumatic system had no previous failures of the TS function that would have been detected solely by the periodic performance of this SR. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on other more frequent testing of the system, and the history of system performance, the impact of this change on safety, if any, is small.

3.6.5.3 Drywell Isolation Valves

SR 3.6.5.3.5 Verify each automatic drywell isolation valve actuates to the isolation position on an actual or simulated isolation signal.

The surveillance test interval of this SR is being increased from once every 18 months to once every 24 months, for a maximum interval of 30 months including the 25% grace period. During the operating cycle, automatic drywell isolation valve isolation times are tested per SR 3.6.5.3.4 in accordance with the In-service Testing Program. Stroke testing of drywell isolation valves tests a significant portion of the circuitry as well as the mechanical function, which will detect failures of this circuitry or failures with valve movement. The frequency of this testing is typically quarterly, unless approved relief has been granted justifying less frequent testing.

A review of the applicable River Bend surveillance history demonstrated that the drywell isolation valves had no previous failures of the TS function that would have been detected solely by the periodic performance of this SR. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on other more frequent testing of the system, and the history of system performance, the impact of this change on safety, if any, is small.

3.7.1 Standby Service Water (SSW) System and Ultimate Heat Sink (UHS)

SR 3.7.1.5 Verify each SSW subsystem actuates on an actual or simulated initiation signal.

The surveillance test interval of this SR is being increased from once every 18 months to once every 24 months, for a maximum interval of 30 months including the 25% grace period. This SR verifies that the automatic isolation valves of the SSW System will automatically switch to the safety or emergency position to provide cooling water exclusively to the safety related equipment during an accident event. This SR also verifies the automatic start capability of the SSW pump and cooling tower fans in each subsystem. The SSW subsystems are redundant so that no single-failure prevents accomplishing the safety function of providing the required cooling. The SSW system pumps and valves are tested quarterly in accordance with the In-service Testing Program (some valves may have independent relief justifying less frequent testing). This testing ensures that the major components of the systems are capable of performing their design function. Additionally, valves in the flow path are verified to be in the correct position monthly (i.e., SR 3.7.1.4). Since most of the components and associated circuits are tested on a more frequent basis, this testing would indicate any degradation to the SSW System which would result in an inability to start based on a demand signal.

A review of the applicable River Bend surveillance history demonstrated that the SSW subsystems had only one previous failure of the TS function that would have been detected solely by the periodic performance of this SR.

(a) On March 25, 2003 SWP-SOV220A failed to remain closed per a non-Technical Specification procedural step with a LOCA signal applied. A failed relay was suspected. Investigation determined that LOCA relay 3A-2-ISCA06 failed. Replaced relay 3A-2-

ISCA06 with new Agastat Model EGPI002 relay and retested satisfactorily. An additional failure was identified, listed below, that would not have prevented the performance of the required safety function of the equipment: 1) Chiller CHL1A tripped unexpectedly after 15 minutes in a non-Technical Specification procedure step. Troubleshooting determined that the first hit was SWP-P3A. During circuit troubleshooting, no faults were found. All terminations were checked tight, and the fault could not be duplicated. Retesting was performed satisfactorily. The identified failure is unique and does not occur on a repetitive basis and is not associated with a time-based failure mechanism.

There are a total of eight Agastat relay failures over the review period. Of the eight Agastat relay failures, four failures were Model EGPI, one was Model EGPD, one was Model ETR14D3N and two were Model ETR14D3G. In all eight Agastat relay failures, the defective relays were replaced. Two of the Agastat Model EGPI failures were in the RHR Equipment Room Ambient Temperature function of the Primary Containment Isolation logic in 2002 and the Main Steam Line Isolation function of the Primary Containment Isolation Logic circuitry in 2007. One of the Agastat Model EGPI failures occurred in 2003 and was in the Compressor C3A Seal Makeup Isolation Valve auto closure circuit and the fourth Agastat EGPI failure occurred in 2008 and was in the DIV I EDG Trip Logic. The Agastat Model EGPD relay failure occurred in 2006 and the relay is utilized in the Reactor Vessel Pressure Low function of the Relief and Low Low Set - Relief Function logic. The Agastat Model ETR14D3N relay failure occurred in 1999 and the relay is utilized in the Containment Unit Cooler System. One Agastat Model ETR14D3G relay failure occurred in 1999 and was in Chiller HVK-CHL1A load sequencing circuit and the second Agastat Model ETR14D3G relay failure occurred in 2000 and was in Chiller HVK-CHL1C load sequencing circuit. For several of the historical failures, detailed evaluation indicated that the relays were not in the plant programs due to an oversight in assigning identification numbers to skid mounted equipment subcomponents. This oversight resulted in some relays being left in service past their required service replacement dates, with resulting relay failures. The plant subsequently evaluated all skid mounted equipment to ensure that the subcomponents were identified and included in the preventative maintenance program. This activity resulted in the upgrading of a number of relays.

The Chiller Main Lube Oil Pump failure occurred in 2008 and the Pump was replaced. There are no time-based mechanisms apparent in these failures. Therefore, these failures are unique and any subsequent failures would not result in a significant impact on system/component availability. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on other more frequent testing of the system, system design, the history of system performance, and the corrective action taken for the relay failures the impact of this change on safety, if any, is small.

3.7.2 Control Room Fresh Air (CRFA) System

SR 3.7.2.3 Verify each CRFA subsystem actuates on an actual or simulated initiation signal.

The surveillance test interval of this SR is being increased from once every 18 months to once every 24 months, for a maximum interval of 30 months including the 25% grace period. The Control Room Fresh Air subsystems are redundant so that no single-failure prevents accomplishing the safety function. More frequent verification of portions of the Control Room Fresh Air System function is accomplished by operating each Control Room Ventilation subsystem and heaters every 31 days (SR 3.7.2.1).

A review of the applicable River Bend surveillance history demonstrated that the Control Room Fresh Air (CRFA) System had no previous failures of the TS function that would have been detected solely by the periodic performance of this SR. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on other more frequent testing of the system, system design, and the history of system performance, the impact of this change on safety, if any, is small.

3.7.3 Control Room Air Conditioning (AC) System

SR 3.7.3.1 Verify each control room AC subsystem has the capability to remove the assumed heat load.

The surveillance test interval of this SR is being increased from once every 18 months to once every 24 months, for a maximum interval of 30 months including the 25% grace period. This SR verifies that the heat removal capability of the system is sufficient to remove the control room heat load assumed in the safety analysis. The SR consists of a combination of testing and calculation. The system is normally operating; thus, malfunctions of the cooling units can be detected by Operations personnel and corrected. The active components and power supplies of the control room AC system are designed with redundancy to ensure that a single-failure will not prevent system operability.

A review of the applicable River Bend surveillance history demonstrated that the Control Room Air Conditioning System had no previous failures of the TS function that would have been detected solely by the periodic performance of this SR. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on other more frequent observation of the system performance, system design, and the history of performance testing, the impact of this change on safety, if any, is small.

3.7.5 Main Turbine Bypass System

SR 3.7.5.2 Perform a system functional test.
SR 3.7.5.3 Verify the TURBINE BYPASS SYSTEM RESPONSE TIME is within limits.

The surveillance test interval of these SRs is being increased from once every 18 months to once every 24 months, for a maximum interval of 30 months including the 25% grace period. These tests ensure that on increasing main steam line pressure events, the main turbine bypass system will operate as designed within required response times. More frequent verification of portions of the main turbine bypass system is accomplished by SR 3.7.5.1, which requires that each main turbine bypass valve be completely cycled once every 31 days. This test demonstrates that the valves are mechanically operable and detects significant failures affecting system operation.

A review of the applicable River Bend surveillance history demonstrated that the main turbine bypass system had no previous failures of the TS functions that would have been detected solely by the periodic performance of these SRs. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on other more frequent testing of the system, and the history of system performance, the impact of this change on safety, if any, is small.

3.8.1 AC Sources-Operating

SR 3.8.1.8 Verify manual transfer of unit power supply from the normal offsite circuit to the required alternate offsite circuit

SR 3.8.1.9 Verify each DG rejects a load greater than or equal to its associated single largest post accident load and following load rejection, the engine speed is maintained less than nominal plus 75% of the difference between nominal speed and the overspeed trip setpoint or 15% above nominal, whichever is lower.

SR 3.8.1.10 Verify each DG operating at a power factor ≤ 0.9 does not trip and voltage is maintained ≤ 4784 V for DG 1A and DG 1B and ≤ 5400 V for DG 1C during and following a load rejection of a load ≥ 3030 kW and ≤ 3130 kW for DGs 1A and 1B and ≥ 2500 kW and ≤ 2600 kW for DG 1C.

SR 3.8.1.11 Verify on an actual or simulated loss of offsite power signal:

a. De-energization of emergency buses;
b. Load shedding from emergency buses for Divisions I and II; and
c. DG auto-starts from standby condition and:
   1. energizes permanently connected loads in ≤ 10 seconds for DG 1A and DG 1B and ≤ 13 seconds for DG 1C,
   2. energizes auto-connected shutdown loads,
   3. maintains steady state voltage ≥ 3740 V and ≤ 4580 V,
   4. maintains steady state frequency ≥ 58.8 Hz and ≤ 61.2 Hz, and
   5. supplies permanently connected and auto-connected shutdown loads for ≥ 5 minutes.

SR 3.8.1.12 Verify on an actual or simulated Emergency Core Cooling System (ECCS) initiation signal each DG auto-starts from standby condition and:

a. For DG 1C during the auto-start maintains voltage ≤ 5400 V and frequency ≤ 66.75 Hz;
b. In ≤ 10 seconds for DG 1A and DG 1B and ≤ 13 seconds for DG 1C after auto-start and during tests, achieves voltage ≥ 3740 V and ≤ 4580 V;
c. In ≤ 10 seconds for DG 1A and DG 1B and ≤ 13 seconds for DG 1C after auto-start and during tests, achieves frequency ≥ 58.8 Hz and ≤ 61.2 Hz; and
d. Operates for ≥ 5 minutes.

SR 3.8.1.13 Verify each DG's automatic trips are bypassed on an actual or simulated ECCS initiation signal except:
- a. Engine overspeed; and
- b. Generator differential current.

SR 3.8.1.14 Verify each DG operating at a power factor ≤ 0.9 operates for ≥ 24 hours:
- a. For DG 1A and DG 1B loaded ≥ 3030 kW and ≤ 3130 kW; and
- b. For DG 1C:
  1. For ≥ 2 hours loaded ≥ 2750 kW and ≤ 2850 kW, and
  2. For the remaining hours of the test loaded ≥ 2500 kW and ≤ 2600 kW.

SR 3.8.1.15 Verify each DG starts and achieves, in ≤ 10 seconds for DG 1A and DG 1B and ≤ 13 seconds for DG 1C, voltage ≥ 3740 V and ≤ 4580 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz

SR 3.8.1.16 Verify each DG:
- a. Synchronizes with offsite power source while loaded with emergency loads upon a simulated restoration of offsite power;
- b. Transfers loads to offsite power source; and
- c. Returns to ready-to-load operation.

SR 3.8.1.17 Verify, with a DG operating in test mode and connected to its bus, an actual or simulated ECCS initiation signal overrides the test mode by:
- a. Returning DG to ready-to-load operation; and
- b. Automatically energizing the emergency loads from offsite power.

SR 3.8.1.18 Verify the sequence time is within ± 10% of design for each load sequence timer.

SR 3.8.1.19 Verify, on an actual or simulated loss of offsite power signal in conjunction with an actual or simulated ECCS initiation signal:
- a. De-energization of emergency buses;
- b. Load shedding from emergency buses for Divisions I and II; and
- c. DG auto-starts from standby condition and:
  1. energizes permanently connected loads in ≤ 10 seconds for DG 1A and DG 1B and ≤ 13 seconds for DG 1C,
  2. energizes auto-connected emergency loads,
  3. achieves steady state voltage ≥ 3740 V and ≤ 4580 V,
  4. achieves steady state frequency ≥ 58.8 Hz and ≤ 61.2 Hz, and
  5. supplies permanently connected and auto-connected emergency loads for ≥ 5 minutes.

The surveillance test interval of these SRs is being increased from once every 18 months to once every 24 months, for a maximum interval of 30 months including the 25% grace period. The River Bend Class 1E AC distribution system supplies electrical power to three divisional load groups, with each division powered by an independent Class 1E 4.16 kV Engineered Safety Feature (ESF) bus. Each ESF bus has two separate and independent offsite sources of power. Each ESF bus has a dedicated onsite diesel generator (DG). The ESF systems of any two of the three divisions provide for the minimum safety functions necessary to shut down the unit and maintain it in a safe shutdown condition. This design provides substantial redundancy in AC power sources. The DGs are infrequently operated; thus, the risk of wear-related degradation is minimal. Historical testing and surveillance testing during operation prove the ability of the diesel engines to start and operate under various load conditions. Diesel Generator loading is listed on USAR Tables 8.3-2 and 3. Through the normal engineering design process, all load additions and deletions are tracked and any changes to loading are verified to be well within the capacity of their power sources. More frequent testing of the AC sources is also required as follows:

* Verifying correct breaker alignment and indicated power availability for each required offsite circuit every 7 days (i.e., SR 3.8.1.1);
* Verifying the DG starting and load carrying capability is demonstrated every 31 days (i.e., SRs 3.8.1.2 and 3.8.1.3), and ability to continuously supply makeup fuel oil is also demonstrated every 31 days (i.e., SR 3.8.1.6);
* Verifying the ability of each DG to reach rated speed and frequency within required time limits every 184 days (i.e., SR 3.8.1.7) will provide prompt identification of any substantial DG degradation or failure;
* Verifying the necessary support for DG start and operation as well as verifying the DG factors that are subject to degradation due to aging, such as fuel oil quality, (i.e., SRs 3.8.1.4, 3.8.1.5, 3.8.3.1, 3.8.3.2, 3.8.3.3, and 3.8.3.4) are required every 31 days and/or prior to addition of new fuel oil.

A review of the applicable River Bend surveillance history for the AC Sources demonstrated there have been three previous failures of the TS functions that would have been detected solely by the periodic performance of these SRs.

(b) On June 27, 1999 HVK-CHL1A chiller failed to sequence on in the maximum allowed time of 220.1 seconds (SRs 3.8.1.11 and 3.8.1.18). The chiller sequenced on as noted in a required Technical Specification test procedure step in 241.5 sec. Relay HVKA01-62 was determined to have failed and was replaced with a new Agastat Model ETR14D3G003. Other failures were identified, listed below, that would not have prevented the performance of the required safety function of the equipment or were event driven failures that were either associated with the performance of the surveillance test steps or with equipment test setup, and have no impact on the system availability: 1) The as-found LPCS pump start time in a required Technical Specification test procedure step was 2.25 seconds (Allowable value is ≥ 1.8 to ≤ 2.2 seconds). An evaluation stated that although outside the TS limits, start time of 2.25 seconds did not affect the Diesel Gen, LPCS or RHR "A" systems ability to perform their required safety functions. Relay TDR E21A-K151 was replaced with a new Model ETR14D3BC2004002 relay to minimize down time - post replacement test of old relay found time delay Satisfactory at 2.0 seconds. 2) In a required Technical Specification test procedure step, E12-MOVF064A did not auto open but was opened manually. Test procedure comment note 20 states that steps 7.18, 7.19 and 7.20 were performed before step 7.4.34. This was a change to the sequencing steps which caused the need to manually open the valve. 3) Chiller tripped on high bearing temperature. Troubleshooting calibrated time delay relays and relay 62-1HVKC01 required adjustment. The identified failure is unique and does not occur on a repetitive basis and is not associated with a time-based failure mechanism.

(c) On April 5, 2000 Chiller CHL1C failed to start within the required time of 180.9 to 221.1 seconds in a procedure Technical Specification required step(SR 3.8.1.11 and 3.8.1.18). The time recorded was 240 seconds following output breaker closure. Time delay relay HVKC01-62 was replaced with a new Agastat Model ETR14D3GC2. Other failures were identified, listed below, that would not have prevented the performance of the required safety function of the equipment or were event driven failures that were either associated with the performance of the surveillance test steps or with equipment test setup, and have no impact on the system availability: 1) HVL-FN1 failed to start as expected in a non-Technical Specification required step due to clogged vent in valve HVL-AOD427. A Work Order replaced a bad solenoid SOV427 on AOD427. An investigation determined that this was a functional failure of non-TS equipment required for TSC habitability. 2) Fan HVF-FLT2B failed to start as expected in a non-Technical Specification required step. The investigation into this determined that there was no mechanical or electrical problem with the fan or related components. The procedure did not provide instructions for the operator to allow time for the system flows and pressures to stabilize before manipulating the controls and aligning the system for the next iteration in the STP. 3) E12-F064A failed to open when expected in a non-Technical Specification step due to valve sequencing in the test procedure. The investigation determined that there was no mechanical or electrical problem with the fan or related components. The procedure did not provide instructions for the operator to allow time for the system flows and pressures to stabilize before manipulating the controls and aligning the system for the next iteration in the test procedure." The identified failure is unique and does not occur on a repetitive basis and is not associated with a time-based failure mechanism.

(d) On March 3, 2008, Chiller HVK-CHL1C tripped (failed) approximately 15 minutes into the test run. It was determined that Chiller Main Lube Oil Pump was drawing excessive current (4 amps when rated at 2.5 amps). This pump HVKCHL1CPL was replaced on 5/30/02 for same reason. The HVK-CHL1CPL pump was replaced with new pump and retested satisfactorily. An additional failure was identified when the VOM continuity measurement at H13-PNL743 Bay E in a non-Technical Specification step of the procedure had an unstable reading and settled at 13 ohm. Troubleshooting determined that DIV I EDG LOCA relay 3A-2-ISCA01 in H13-P851D had failed and was replaced with a new relay. A investigation revealed that the relay's contacts are in the DIV 1 EDG Trip Logic and the Diesel is considered inoperable until repaired.
Other failures were identified, listed below, that would not have prevented the performance of the required safety function of the equipment:

1) E12-MOVF037A would not close in a non-Technical Specification procedure step. Investigation determined that the cause of the failure was bad auxiliary contacts in EHS-MCC2C breaker cubicle. The auxiliary contacts were replaced and retested satisfactorily. Non-TS function.
2) Following performance of a non-Technical Specification procedure step received Div I EDG HIGH VIBR TRIP alarm, EDG was secured per procedure. Troubleshooting found that the alarm was caused by a leaking check valve in the vibration trip tubing. A Work Order replaced the faulty check valve. This failure had no impact on the ability of the Div I EDG to perform its safety function.
3) During test setup, HVR-AOD18B would not close as indicated at H13-P863 for the Control Board Lineup for LOCA. A Work Order replaced HVR-SOV18B with a new ASCO solenoid valve and the Nupro filter was replaced. Non-TS function associated with test setup.
4) C71-S003F did not indicate tripped following LOP (Loss of Power) test. When panel door opened for inspection, determined that breaker was open (electrically) but handle was stuck in closed position. No deficiencies found. The identified

failure is unique and does not occur on a repetitive basis and is not associated with a time-based failure mechanism

No similar failures of Chiller Main Lube Oil Pumps are identified over the review period; therefore, the failure is not repetitive in nature. There are a total of eight Agastat relay failures over the review period. Of the eight Agastat relay failures, four failures were Model EGPI, one was Model EGPD, one was Model ETR14D3N and two were Model ETR14D3G. In all eight Agastat relay failures, the defective relays were replaced. Two of the Agastat Model EGPI failures were in the RHR Equipment Room Ambient Temperature function of the Primary Containment Isolation logic in 2002 and the Main Steam Line Isolation function of the Primary Containment Isolation Logic circuitry in 2007. One of the Agastat Model EGPI failures occurred in 2003 and was in the Compressor C3A Seal Makeup Isolation Valve auto closure circuit and the fourth Agastat EGPI failure occurred in 2008 and was in the DIV I EDG Trip Logic. The Agastat Model EGPD relay failure occurred in 2006 and the relay is utilized in the Reactor Vessel Pressure Low function of the Relief and Low Low Set - Relief Function logic. The Agastat Model ETR14D3N relay failure occurred in 1999 and the relay is utilized in the Containment Unit Cooler System. One Agastat Model ETR14D3G relay failure occurred in 1999 and was in Chiller HVK-CHL1A load sequencing circuit and the second Agastat Model ETR14D3G relay failure occurred in 2000 and was in Chiller HVK-CHL1C load sequencing circuit. For several of the historical failures, detailed evaluation indicated that the relays were not in the plant programs due to an oversight in assigning identification numbers to skid mounted equipment subcomponents. This oversight resulted in some relays being left in service past their required service replacement dates, with resulting relay failures. The plant subsequently evaluated all skid mounted equipment to ensure that the subcomponents were identified and included in the preventative maintenance program. This activity resulted in the upgrading of a number of relays.

The Chiller Main Lube Oil Pump failure occurred in 2008 and the Pump was replaced. There are no time-based mechanisms apparent in these failures. Therefore, these failures are unique and any subsequent failures would not result in a significant impact on system/component availability.

Although the Control Room Chillers did not exhibit repetitive failures of components and the fact that they were only a small contributor to the EDG LOOP/LOCA testing, the failure of the Chillers to sequence and operate as a part of the AC sources testing was identified as a potential issue for surveillance extension. There was no trend for the events that prevented starting and operation of the Control Room Chillers however; the overall material condition was questioned.

As a result of the concerns, RBS has identified the Control Room Chiller system as a plant top 10 priority item due to reliability concerns. The Material Condition indicator is RED due to chronic issues associated with breakers and the operations indicator is white due to 2 unplanned LCO entries. The increased focus on this equipment ensures that the material condition of this system will continue to be evaluated during the upcoming operational cycles independent of the 24-Month fuel cycle extension. This increased focus will ensure that the system is acceptable to support the extended surveillance frequencies.

As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on other more frequent testing of the system, Maintenance Rule tracking, system design, the history of system performance, and the corrective action for the breaker failures the impact of this change on safety, if any, is small.

3.8.4 DC Sources-Operating

SR 3.8.4.3 Verify battery cells, cell plates, and racks show no visual indication of physical damage or abnormal deterioration.

SR 3.8.4.4 Remove visible corrosion, and verify battery cell to cell and terminal connections are coated with anti-corrosion material.

SR 3.8.4.5 Verify battery connection resistance is

$\leq$ 1.5 E-4 ohm for inter-cell connections,

$\leq$ 1.5 E-4 ohm for inter-rack connections,

$\leq$ 1.5 E-4 ohm for inter-tier connections, and

$\leq$ 1.5 E-4 ohm for terminal connections

SR 3.8.4.6 Verify each battery charger supplies $\geq$ 300 amps for chargers 1A and 1B and $\geq$ 50 amps for charger 1C at $\geq$ 130.2 V for $\geq$ 8 hours.

SR 3.8.4.7 Verify battery capacity is adequate to supply, and maintain in OPERABLE status, the required emergency loads for the design duty cycle when subjected to a battery service test.

The surveillance test interval of these SRs is being increased from once every 18 months to once every 24 months, for a maximum interval of 30 months including the 25% grace period. SR 3.8.4.1 and SR 3.8.6.1 are performed every 7 days to verify battery terminal voltage and pilot cell float voltage, electrolyte level and specific gravity, respectively. SR 3.8.6.2 and SR 3.8.6.3 are performed every 92 days to verify each cell float voltage, each cell electrolyte level, each cell specific gravity, and pilot cell temperature. SR 3.8.4.2 is performed every 92 days to verify no visible battery terminal/connector corrosion or high resistance. These more frequent surveillances will provide prompt identification of any substantial degradation or failure of the battery and/or battery chargers.

A review of the applicable River Bend surveillance history demonstrated that the DC electric power subsystem had no previous failures of the TS functions that would have been detected solely by the periodic performance of these SRs. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on other more frequent testing of the system, and the history of system performance, the impact of this change on safety, if any, is small.

Additionally, upon approval of this amendment request, commitments outlined in the River Bend USAR related to RG 1.32, "Criteria for Safety-Related Electric Power Systems for Nuclear Power Plants," RG 1.129, "Maintenance, Testing, and Replacement of Large Lead Storage Batteries for Nuclear Power Plants," and to IEEE-450, "Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications," to perform the battery service test (i.e., SR 3.8.4.7) during refueling outages, or at some other outage, with intervals between tests "not to exceed 18 months," will be revised to reflect intervals between tests "not to exceed 30 months."

5.5.2. Primary Coolant Sources Outside Containment

5.5.2.b The program shall include the following: Integrated leak test requirements for each system at refueling cycle intervals or less.

TS 5.5.2 the frequency for Integrated leak testing is specified as each refueling interval. The Surveillance Test Interval of this SR is being increased from once every 18 Months to once every 24 months for a maximum interval of 30 Months including the 25% grace period. This requirement establishes a program to reduce leakage from those portions of systems outside containment that could contain highly radioactive fluids during a serious transient or accident to as low as practical levels. Specifically, the program requires an "Integrated leak test requirement for each system at refueling cycle intervals or less." The change to 24 month operating cycles will increase the testing interval. This change to the testing requirement has been evaluated and determined that the impact, if any, on safety is small. This conclusion is based on the fact that most portions of the subject systems included in this program are visually walked down, while the plant is operating, during plant testing and/or operator/system engineer walkdowns. In addition, housekeeping/safety walkdowns also serve to detect any gross leakage. If leakage is observed from these systems, corrective actions will be taken to repair the leakage. Finally, the plant radiological surveys will also identify any potential sources of leakage. These visual walkdowns and surveys provide monitoring of the systems at a greater frequency then once per refueling cycle, and support the conclusion that the impact, if any, on safety is small as a result of the proposed changes.

A review of the surveillance test history was performed to validate the above conclusion. This historical review of the surveillance test history demonstrates that there are no failures that would invalidate the conclusion that the impact on system availability, if any, is small.

5.5.7 Ventilation Filter Testing Program (VFTP)

5.5.7 A program shall be established to implement the following required testing of Engineered Safety Feature (ESF) filter ventilation systems at the frequencies specified in Regulatory Guide 1.52, Revision 2.

While this specified frequency of testing ESF filter ventilation systems does not explicitly state "18 months," TS Section 5.5.7 requires testing frequencies in accordance with RG 1.52, "Design, Testing and Maintenance Criteria for Post Accident Engineered-Safety-Feature Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants," which does reference explicit "18 month" test intervals for various performance characteristics. With this change, these performance tests are being increased from once every 18 months to once every 24 months, for a maximum interval of 30 months including the 25% grace period. This exception to the RG 1.52 interval is explicitly addressed in the change to River Bend TS 5.5.7. Furthermore, this revision to the River Bend commitment to RG 1.52 will be reflected in a revision to the USAR and provided in accordance with 10CFR50.71, "Maintenance of records, making of reports," paragraph (e). Administrative Control Specification 5.5.7 is revised to state (inserted text shown underlined):

> 5.5.7 A program shall be established to implement the following required testing of Engineered Safety Feature (ESF) filter ventilation systems at the frequencies specified in Regulatory Guide 1.52, Revision 2, except that testing specified at a frequency of 18 months is required at a frequency of 24 months.

In addition to the 24-month testing, ventilation filter (HEPA and charcoal) testing will continue to be performed in accordance with the other frequencies specified in RG 1.52: (1) on initial installation and (2) following painting, fire, or chemical release in any ventilation zone communicating with the system. Additionally, RG 1.52 requires a sample of the charcoal adsorber be removed and tested after each 720 hours of system operation, and an in-place charcoal test be performed following removal of these samples if the integrity of the adsorber section was affected. This proposed amendment request will not change the commitment to perform these required tests.

A review of the applicable River Bend surveillance history demonstrated that the ESF ventilation systems had no previous failures of the TS functions that would have been detected solely by the periodic performance of SRs that reference performance of the VFTP of Specification 5.5.7. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on other more frequent testing of the system, and the history of system performance, the impact of this change on safety, if any, is small.

5.5.14 Control Room Envelope Habitability Program

5.5.14.d The program shall include the following elements: Measurement, at designated locations, of the CRE pressure relative to all external areas adjacent to the CRE boundary during the pressurization mode of operation by one subsystem of the CRFA System, operating at the flow rate required by the VFTP, at a Frequency of 18 months on a STAGGERED TEST BASIS.

This program was placed in the Technical Specifications as part of Amendment 154 dated November 16, 2007 which adopted Technical Specifications Task Force (TSTF)-448, Revision 3, "Control Room envelope Habitability" using consolidated line item improvement process. This TSTF contains proposed Technical Specification wording. For the frequency of the above portion of the program the TSTF proposes a frequency of [18] months in brackets. The brackets are provided to permit each plant to place the correct frequency in their proposed change. The TSTF states that "Paragraph d requires measurement, at designated locations, of the CRE pressure relative to all external areas adjacent to the CRE boundary during the pressurization mode of operation by one train of the CREFS, operating at the flow rate required by the Ventilation Filter Test Program, at a Frequency of [18] months on a STAGGERED TEST BASIS. The test data is to be trended and used as part of the [18] month assessment of the CRE boundary required by Paragraph c. The measurement of the differential pressure between the CRE and adjacent areas provides a gross indication of barrier integrity and is useful in monitoring the health of the CRE barrier between performances of inleakage testing. NEI 99-

03, Section 9.3, "Periodic Evaluations," recommends periodic evaluation of the CRE boundary integrity, including comparison to previous assessments, to examine the performance history. However, as pointed out in Generic Letter 2003-01, the usefulness of differential pressure measurements is very limited and the importance of data from these measurements should not be overemphasized. Therefore, the Control Room Envelope Habitability Program requires measuring differential pressure every [18] months on a STAGGERED TEST BASIS in a manner similar to the current requirement in the Technical Specifications. The results will be trended and compared to positive pressure measurements taken, or to be taken, during CRE inleakage testing. These evaluations will be used as part of an assessment of CRE boundary integrity between CRE boundary inleakage tests. This approach balances the desire to assess CRE habitability between the performances of inleakage tests with the complexities inherent in the interpretation of differential pressure measurements." Reviewing other BWR 6 plants that have implemented both the 24 month cycle and the TSTF 448 line item improvement show that both have frequencies of 24 month for this program requirement.

Based on the above, the impact of this change on safety, if any, is small.

B. Channel Calibration Changes

NRC GL 91-04 requires that licensees address instrument drift when proposing an increase in the surveillance interval for calibrating instruments that perform safety functions including providing the capability for safe shutdown. The effect of the increased calibration interval on instrument errors must be addressed because instrument errors caused by drift were considered when determining safety system setpoints and when performing safety analyses. NRC GL 91-04 identifies seven steps for the evaluation of instrumentation calibration changes. These seven steps are discussed in Attachment 1 to this submittal. In that discussion, a description of the methodology used by River Bend for each step is summarized. The detailed methodology is provided in Attachment 6.

The following are the calibration-related TS SRs being proposed for revision from 18 months to 24 months, for a maximum interval of 30 months (considering the 25% grace period allowed by TS SR 3.0.2). In each instance, the instrument channel loop drift was evaluated in accordance with Setpoint Methodology EN-IC-S-007-R Rev. 0 "Methodology For The Generation of Instrument Loop Uncertainty & Setpoint Calculations" and Drift Design Guide ECH-NE-08-00015, Revision 0 "Instrument Drift Analysis Design Guide"

The projected 30-month drift values for many of the instruments analyzed from the historical as-found/as-left evaluation shows sufficient margin between the current plant setpoint and the allowable value to compensate for the 30-month drift. For each instrument function that has a channel calibration proposed frequency change to 24 months, the associated setpoint calculation assumes (or will be revised prior to implementation to assume) a consistent or conservative drift value appropriate for a 24-month calibration interval. All revised setpoint calculations have been (or will be) completed in accordance with the guidance provided in RG 1.105, Rev.1 "Instrument Setpoints," as implemented by the River Bend setpoint methodology, and the Instrument Society of America (ISA) Standard 67.04, 1975. These calculations determine the instrument uncertainties, setpoints, and allowable values for the affected functions. Where indicated, proposed allowable value changes have been determined to be required. The allowable values have been determined in a manner suitable to establish limits for their application. As such, the TS allowable values ensure that sufficient margins are maintained in the applicable safety analyses to confirm the affected instruments are capable of performing their intended design function. Also, review of the applicable safety analysis concluded that the setpoints, allowable values, and projected 30-month drift confirmed the safety limits and safety analysis assumptions remain bounding.

Below is a summary of the specific application of this methodology to the River Bend 24-month fuel cycle extension project, as well as any required allowable value changes. Where optional methods are presented in Attachment 6, and where other alternate engineering justifications are allowed, the rationale for the selected method and alternate justification is summarized with the associated instrument calibration surveillance affected (e.g., for channel groupings having less than 30 calibrations, which is required to qualify for valid statistical evaluations).

3.3.1.1 Reactor Protection System (RPS) Instrumentation

The RPS initiates a reactor scram when one or more monitored parameters exceed their specified limit, to preserve the integrity of the fuel cladding and the Reactor Coolant System (RCS), and minimize the energy that must be absorbed following a loss of coolant accident (LOCA).

SR 3.3.1.1.13 Perform CHANNEL CALIBRATION.
- Function 3, Reactor Vessel Steam Dome Pressure-High
- Function 4, Reactor Vessel Water Level-Low, Level 3
- Function 5, Reactor Vessel Water Level-High, Level 8
- Function 7, Drywell Pressure-High
- Function 8.a, Scram Discharge Volume Water Level-High, Transmitter/Trip Unit
- Function 10, Turbine Control Valve Fast Closure, Trip Oil Pressure-Low

For these functions, no revisions to TS allowable values or safety analyses result from the GL 91-04 evaluations (e.g., statistical evaluation of historical drift factored into setpoint calculations). Any necessary revisions to setpoint calculations and calibration procedures to incorporate results of the statistical analysis of the historical as-found minus as-left (AFAL) data will be completed prior to implementation.

A review of the applicable River Bend surveillance history for these Functions demonstrated that the as-found trip setpoint had no previous failure of TS required allowable values that would have been detected solely by the periodic performance of this SR. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on the history of system performance, the impact of this change on safety, if any, is small.

SR 3.3.1.1.13 Perform CHANNEL CALIBRATION.
- Function 1.a, Intermediate Range Monitors, Neutron Flux-High

No revisions to TS allowable values or safety analyses result from the required evaluations. Drift evaluations were not performed for TS Table 3.3.1.1-1 Function 1.a, Intermediate Range Monitors (IRMs), Neutron Flux-High. This is acceptable because of the design requirements for the instruments and more frequent functional testing (i.e., once per 7 days). Before the IRM detectors are used for operation, an overlap check is performed to determine if the instruments are reading and tracking with the power range (i.e., SR 3.3.1.1.7) or the source range neutron detectors (i.e., SR 3.3.1.1.6), as applicable. Furthermore, when the IRM trip is required to be operable, a channel functional test is performed on the IRM trip function every 7 days in accordance with SR 3.3.1.1.4.

A review of the applicable River Bend surveillance history for the IRM channels demonstrated that the as-found trip setpoint for these functions had no previous failures of TS required allowable values that would have been detected solely by the periodic performance of this SR. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on the history of system performance, the impact of this change on safety, if any, is small.

<u>SR 3.3.1.1.13</u> Perform CHANNEL CALIBRATION.
- Function 6, Main Steam Isolation Valve-Closure
- Function 8.b, Scram Discharge Volume Water Level-High, Float Switch
- Function 9, Turbine Stop Valve Closure

No revisions to TS allowable values or safety analyses result from the required evaluations. Drift evaluations were not performed for TS Table 3.3.1.1-1 Functions 6 (MSIV limit switches), 8.b (scram discharge volume float switches), and 9 (turbine stop valve (TSV) limit switches). The limit and float switches that perform these functions are mechanical devices that require mechanical adjustment only; drift is not applicable to these devices. The limit switches are functionally tested quarterly (i.e., SR 3.3.1.1.9) to verify operation.

A review of the applicable River Bend surveillance history for these limit switch channels demonstrated that the as-found trip setpoint for these functions had only one previous failure of TS required allowable values that would have been detected solely by the periodic performance of this SR. SR 3.3.1.1.13 experienced one failure associated with Function 6 (Main Steam Isolation Valve-Closure function).

(a) On October 14, 1997, B21-F028A MSL A OUTBD MSIV, Switch # 4 & #5 trip setpoint was found outside of the allowable value and was corrected by adjustment of the limit switch.

No similar failures are identified; therefore, the failure is not repetitive in nature. No time based mechanisms are apparent. Therefore, this failure is unique and any subsequent failures would not result in a significant impact on system/component availability. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on the history of system performance, the impact of this change on safety, if any, is small.

SR 3.3.1.1.16 Verify Turbine Stop Valve Closure and Turbine Control Valve Fast Closure Trip Oil Pressure-Low Functions are not bypassed when THERMAL POWER is ≥ 40% RTP.

This SR ensures that scrams initiated from the Turbine Stop Valve Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure–Low Functions will not be inadvertently bypassed when THERMAL POWER is ≥ 40% RTP. This involves calibration of the bypass channels.

No revisions to TS allowable values or safety analyses result from the GL 91-04 evaluations (e.g., statistical evaluation of historical drift factored into setpoint calculations). Any necessary revisions to setpoint calculations and calibration procedures to incorporate results of the statistical analysis of the historical AFAL data will be completed prior to implementation.

A review of the applicable River Bend surveillance history for this function demonstrated that the as-found trip setpoint had no previous failures of the TS required allowable value that would have been detected solely by the periodic performance of this SR. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on the history of system performance, the impact of this change on safety, if any, is small.

SR 3.3.1.1.17 Calibrate the flow reference transmitters

Each APRM channel receives one total drive flow signal. The recirculation loop drive flow signals are generated by eight flow units. One flow unit from each recirculation loop is provided to each APRM channel. Total drive flow is determined by each APRM by summing up the flow signals provided to the APRM from the two recirculation loops. This SR is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy.

No revisions to TS allowable values or safety analyses result from the GL 91-04 evaluations (e.g., statistical evaluation of historical drift factored into setpoint calculations). Any necessary revisions to setpoint calculations and calibration procedures to incorporate results of the statistical analysis of the historical AFAL data will be completed prior to implementation.

A review of the applicable River Bend surveillance history for this function demonstrated that the as-found trip setpoint had no previous failures of the TS required allowable value that would have been detected solely by the periodic performance of this SR. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on the history of system performance, the impact of this change on safety, if any, is small.

3.3.1.2 Source Range Monitor (SRM) Instrumentation

The SRMs provide the operator with information relative to very low neutron flux levels in the core. Specifically, the SRM indication is used by the operator to monitor the approach to criticality and to determine when criticality is achieved. During refueling, shutdown, and low power operations, the primary indication of neutron flux levels is provided by the SRMs to monitor reactivity changes during fuel or control rod movement and give the control room operator early indication of unexpected subcritical multiplication that could be indicative of an approach to criticality.

SR 3.3.1.2.6 Perform CHANNEL CALIBRATION.

No revisions to TS allowable values or safety analyses result from the required evaluations. Drift evaluations were not performed for SRMs. This is acceptable because there are no trip setpoints or allowable values specified by the TS or credited in accident or safe shutdown analyses. There are also more frequent Channel Checks(SR 3.3.1.2.1 and SR 3.3.1.2.3) and functional testing(SR 3.3.1.2.5).

Extending the SRM calibration interval from 18 months to 24 months is acceptable if calibration is sufficient to ensure neutron level is observable when the reactor is shutdown. This is verified at least every 24 hours when the reactor is shutdown (i.e., SR 3.3.1.2.4). Also, SRMs satisfy their design function (i.e., are adequately calibrated) when sufficient overlap with the IRMs is demonstrated during startup operations. IRM/SRM overlap is appropriately verified in accordance with SR 3.3.1.1.6. Additionally, SRM response to reactivity changes is distinctive and well known to plant operators and SRM response is closely monitored during these reactivity changes. Therefore, any substantial degradation of the SRMs will be evident prior to the scheduled performance of Channel Calibrations. Based on the above discussion, there will be no significant adverse impact from the surveillance test frequency increase on system reliability.

A review of the applicable River Bend surveillance history for this function demonstrated that there were no previous failures of TS required channel calibration that would have been detected solely by the periodic performance of this SR. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on the history of system performance, the impact of this change on safety, if any, is small.

3.3.3.1 Post Accident Monitoring (PAM) Instrumentation

The primary purpose of the PAM instrumentation is to display plant variables that provide information required by the control room operators during accident situations. This information provides the necessary support for the operator to take the manual actions for which no automatic control is provided.

SR 3.3.3.1.3 Perform CHANNEL CALIBRATION.

No allowable value is applicable to these functions. A separate drift evaluation has not been performed for the PAM instruments based on the design of the PAM instruments and equipment history. The PAM function is supported by a combination of process transmitters, indicators, and recorders. These components differ from other TS instruments in that they are not associated with a function trip, but indication only to the control room operator. As such, these instruments are not expected to function with the same high degree of accuracy demanded of functions with assumed trip actuations for accident detection and mitigation. The PAM devices are expected to maintain sufficient accuracy to detect trends or the existence or non-existence of a condition. The PAM functions require at least two operable channels (except for some PCIV indications) to ensure no single failure prevents the operators from being presented with the information. The functioning status of the PAM instruments is also required more frequently by SR 3.3.3.1.1 (i.e., Channel Check every 31 days).

A review of the applicable River Bend surveillance history for these functions demonstrated that there were only two previous failures of TS required channel calibration that would have been detected solely by the periodic performance of this SR.

On October 7, 1997, an Automatic Primary Containment Isolation Valve, CCP-V133 (Velan Model P1-5502-N-02) failed the close test (Function 12). A review of the history of CCP-VI33 revealed that the only previous maintenance performed on this valve was in March 1990 after it failed its IST test. At that time the valve was disassembled, cleaned, and reassembled. After the current failure, the disc was found stuck in the open position. The valve was cleaned, lapped, blue checked and reassembled. After the maintenance was complete, CCP-VI33 passed its closure test. The identified failure is unique and does not occur on a repetitive basis and is not associated with a time-based failure mechanism.

On December 3, 2002, Recorder CMS-PR2A digital display was found out of tolerance and could not be adjusted within tolerance (Function 7). Investigation found recorder was loading the loop down. The recorder was replaced and a re-span of a new recorder was performed. The identified failure is unique and does not occur on a repetitive basis and is not associated with a time-based failure mechanism.

No similar failures of Velan Model P1-5502-N-02 valves or Westronics Model SV10C-350-113-A00 Recorders are identified; therefore, the failures are not repetitive in nature. No time based mechanisms are apparent. Therefore, these failures are unique and any subsequent failures would not result in a significant impact on system/component availability.

As such, the impact, if any, on PAM system availability is minimal from the proposed change to a 24-month testing frequency. Based on system design and the history of system performance, the impact of this change on safety, if any, is small.

3.3.3.2 Remote Shutdown System

The Remote Shutdown System provides the control room operator with sufficient instrumentation and controls to place and maintain the plant in a safe shutdown condition from a location other than the control room.

<u>SR 3.3.3.2.3</u> Perform CHANNEL CALIBRATION for each required instrumentation channel, except valve position instrumentation.

No allowable value is applicable to these functions. A separate drift evaluation has not been performed for the Remote Shutdown System instrument channels based on the design function and equipment history.

The Remote Shutdown System instrument channels differ from other TS instruments in that they are not associated with an automatic protective action or trip. As such, these instruments are not expected to function with the same high degree of accuracy demanded of functions with assumed trip actuations for accident detection and mitigation. The normally energized Remote Shutdown System instrument channels also require more frequent verification of the functioning status as required by SR 3.3.3.2.1 (i.e., every 31 days).

A review of the applicable River Bend surveillance history demonstrated that the Remote Shutdown System had only one previous failure of the TS function that would have been detected solely by the periodic performance of this SR.

On December 11, 1999, CMS-TI40B was found out of tolerance low and could not adjust within tolerance due to suspected bad signal resistor unit (SRU). The SRU was replaced and checked satisfactorily. The identified failure is unique and is does not occur on a repetitive basis and is not associated with a time-based failure mechanism.

No similar failures are identified; therefore, the failure is not repetitive in nature. No time based mechanisms are apparent. Therefore, this failure is unique and any subsequent failures would not result in a significant impact on system/component availability. As such, the impact, if any, on Remote Shutdown System availability is minimal from the proposed change to a 24-month testing frequency. Based on the history of system performance, the impact of this change on safety, if any, is small.

<u>3.3.4.1 End of Cycle Recirculation Pump Trip (EOC-RPT) Instrumentation</u>

The EOC-RPT instrumentation initiates a recirculation pump trip to reduce the peak reactor pressure and power resulting from turbine trip (TSV closure) or generator load rejection (TCV fast closure) transients to provide additional margin to core thermal minimum critical power ratio (MCPR) Safety Limits.

<u>SR 3.3.4.1.3</u> Perform CHANNEL CALIBRATION.
- Function a, TSV Closure

No revisions to TS allowable values or safety analyses result from the required evaluations. Drift evaluations were not performed for the TSV limit switches. The limit switches that perform these functions are mechanical devices that require mechanical adjustment only; drift is not applicable to these devices. The limit switches are functionally tested quarterly (i.e., SR 3.3.4.1.1) to verify operation.

A review of the applicable River Bend surveillance history for these limit switch channels demonstrated that the as-found trip setpoint for these functions had no previous failures of TS required allowable values that would have been detected solely by the periodic performance of this SR. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on the history of system performance, the impact of this change on safety, if any, is small.

<u>SR 3.3.4.1.3</u> Perform CHANNEL CALIBRATION.
- Function b, TCV Fast Closure, Trip Oil Pressure-Low

No revisions to TS allowable values or safety analyses result from the required evaluations. Any necessary revisions to setpoint calculations and calibration procedures will be completed prior to implementation.

A review of the applicable River Bend surveillance history for these limit switch channels demonstrated that the as-found trip setpoint for these functions had no previous failures of TS required allowable values that would have been detected solely by the periodic performance of this SR. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on the history of system performance, the impact of this change on safety, if any, is small.

<u>SR 3.3.4.1.5</u> Verify TSV Closure and TCV Fast Closure, Trip Oil Pressure-Low Functions are not bypassed when THERMAL POWER is ≥ 40% RTP.

No revisions to TS allowable values or safety analyses result from the GL 91-04 evaluations (e.g., statistical evaluation of historical drift factored into setpoint calculations). Any necessary revisions to setpoint calculations and calibration procedures to incorporate results of the statistical analysis of the historical AFAL data will be completed prior to implementation.

This SR ensures that an EOC-RPT initiated from the Turbine Stop Valve Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure–Low functions will not be inadvertently bypassed when THERMAL POWER is ≥ 40% RTP. This involves calibration of the bypass channels.

A review of the applicable River Bend surveillance history for this function demonstrated that the as-found trip setpoint had no previous failures of the TS required allowable value that would have been detected solely by the periodic performance of this SR. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on the history of system performance, the impact of this change on safety, if any, is small.

3.3.4.2 Anticipated Transient Without Scram Recirculation Pump Trip (ATWS-RPT) Instrumentation

The ATWS-RPT System initiates a recirculation pump trip, adding negative reactivity, following events in which a scram does not (but should) occur, to lessen the effects of an ATWS event. Tripping the recirculation pumps adds negative reactivity from the increase in steam voiding in the core area as core flow decreases. When Reactor Vessel Water Level-Low Low, Level 2 or Reactor Steam Dome Pressure-High setpoint is reached, the recirculation pump motor breakers trip.

SR 3.3.4.2.4 Perform CHANNEL CALIBRATION.
- Function a, Reactor Vessel Water Level–Low Low, Level 2
- Function b, Reactor Steam Dome Pressure-High

For these functions, no revision to TS allowable values or safety analyses result from the GL 91-04 evaluations (e.g., statistical evaluation of historical drift factored into setpoint calculations). Any necessary revisions to setpoint calculations and calibration procedures to incorporate results of the statistical analysis of the historical AFAL data will be completed prior to implementation.

A review of the applicable River Bend surveillance history for these functions demonstrated that the as-found trip setpoint had no previous failures of TS required allowable values that would have been detected solely by the periodic performance of this SR. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on the history of system performance, the impact of this change on safety, if any, is small.

3.3.5.1 Emergency Core Cooling System (ECCS) Instrumentation

The purpose of the ECCS instrumentation is to initiate appropriate responses from the systems to ensure that fuel is adequately cooled in the event of a design basis accident or transient.

SR 3.3.5.1.5 Perform CHANNEL CALIBRATION.
- Function 1.a, 2.a, 4.a, 5.a, Reactor Vessel Water Level–Low Low Low, Level 1
- Function 1.b, 2.b, 3.b, 4.b, 5.b, Drywell Pressure-High
- Function 1.e, 2.e, Reactor Vessel Pressure-Low (Injection Permissive)
- Function 1.f, 1.g, 2.f, LPCS Pump & LPCI Pump A, B, & C Discharge Flow-Low (Bypass)
- Function 3.a, Reactor Vessel Water Level–Low Low, Level 2
- Function 3.c, Reactor Vessel Water Level–High, Level 8
- Function 3.d, Condensate Storage Tank Level-Low
- Function 3.e, Suppression Pool Water Level-High
- Function 3.f, HPCS Pump Discharge Pressure-High (Bypass)
- Function 3.g, HPCS System Flow Rate-Low (Bypass)
- Function 4.d, 5.d, Reactor Vessel Water Level–Low, Level 3 (Confirmatory)
- Function 4.e, 4.f, 5.e, LPCS Pump & LPCI Pump A, B, & C Discharge Pressure-High

No revisions to TS allowable values or safety analyses result from the GL 91-04 evaluations (e.g., statistical evaluation of historical drift factored into setpoint calculations).

Any necessary revisions to setpoint calculations and calibration procedures to incorporate results of the statistical analysis of the historical AFAL data will be completed prior to implementation.

A review of the applicable River Bend surveillance history for these channels demonstrated that the as-found trip setpoint for all these functions had only one previous failure of TS required allowable values that would have been detected solely by the periodic performance of this SR.

(a) On March 23, 2003, trip unit B21-N674L for SR 3.3.5.1.5, Function 3.c was found out of tolerance high and exceeded Technical Specification due to transmitter B21-N073L being out of tolerance low. B21-N073L was adjusted satisfactorily. The identified failure is unique and does not occur on a repetitive basis and is not associated with a time-based failure mechanism.

No similar failures of Rosemount 1154DP5 transmitters are identified; therefore, the failure is not repetitive in nature. No time based mechanisms are apparent. Therefore, this failure is unique and any subsequent failures would not result in a significant impact on system/component availability.

As such, this failure is not indicative of a repetitive failure problem and does not invalidate the conclusion that only on rare occasions do as-found values exceed acceptable limits. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on the history of system performance, the impact of this change on safety, if any, is small.

3.3.5.2 Reactor Core Isolation Cooling (RCIC) System Instrumentation

The purpose of the RCIC System instrumentation is to initiate actions to ensure adequate core cooling when the reactor vessel is isolated from its primary heat sink (the main condenser) and normal coolant makeup flow from the Reactor Feedwater System is unavailable, such that initiation of the low pressure ECCS pumps does not occur.

SR 3.3.5.2.4 Perform CHANNEL CALIBRATION.
- Function 1, Reactor Vessel Water Level-Low Low, Level 2
- Function 2, Reactor Vessel Water Level–High, Level 8
- Function 3, Condensate Storage Tank Level-Low
- Function 4, Suppression Pool Water level-High

For these functions, no revision to TS allowable values or safety analyses result from the GL 91-04 evaluations (e.g., statistical evaluation of historical drift factored into setpoint calculations). Any necessary revisions to setpoint calculations and calibration procedures to incorporate results of the statistical analysis of the historical AFAL data will be completed prior to implementation.

A review of the applicable River Bend surveillance history for these functions demonstrated that the as-found trip setpoint had no previous failures of TS required allowable values that would have been detected solely by the periodic performance of this SR. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on the history of system performance, the impact of this change on safety, if any, is small.

3.3.6.1 Primary Containment and Drywell Isolation Instrumentation

The primary containment and drywell isolation instrumentation automatically initiates closure of appropriate primary containment isolation valves (PCIVs) and drywell isolation valves.

SR 3.3.6.1.5 Perform CHANNEL CALIBRATION.
- Function 1.a, 5.c, Reactor Vessel Water Level-Low Low Low, Level 1
- Function 1.b, Main Steam Line Pressure-Low
- Function 1.c, Main Steam Line Flow-High
- Function 1.d, Condenser Vacuum-Low
- Function 2.a, 4.i, Reactor Vessel Water Level-Low Low, Level 2
- Function 2.b, 3.j, 5.e, Drywell Pressure-High
- Function 3.a, RCIC Steam Line Flow-High
- Function 3.c, RCIC Steam Supply Line Pressure-Low
- Function 3.d, RCIC Turbine Exhaust Diaphragm Pressure-High
- Function 3.i, RCIC/RHR Steam Line Flow-High
- Function 4.a, Differential Flow-High
- Function 5.b, Reactor Vessel Water Level - Low, Level 3
- Function 5.d, Reactor Steam Dome Pressure -High

For these functions, no revision to TS allowable values or safety analyses result from the GL 91-04 evaluations (e.g., statistical evaluation of historical drift factored into setpoint calculations). Any necessary revisions to setpoint calculations and calibration procedures to incorporate results of the statistical analysis of the historical AFAL data will be completed prior to implementation.

A review of the applicable River Bend surveillance history for these channels demonstrated that the as-found trip setpoint for these functions had no previous failure of TS required allowable values that would have been detected solely by the periodic performance of this SR. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on system design and the history of system performance, the impact of this change on safety, if any, is small.

SR 3.3.6.1.5 Perform CHANNEL CALIBRATION.
- Function 1.e, Main Steam Tunnel Temperature-High
- Function 3.e, RCIC Equipment Room Ambient Temperature-High
- Function 3.f, Main Steam Line Tunnel Ambient Temperature-High
- Function 3.h, RHR Equipment Room Ambient Temperature-High
- Function 4.c, RWCU Heat Exchanger Equipment Room Temperature-High
- Function 4.d, RWCU Pump Rooms Temperature-High
- Function 4.e, RWCU Valve Nest Room Temperature-High

- Function 4.f, RWCU Demineralizer Rooms Temperature-High
- Function 4.g, RWCU Receiving Tank Room Temperature-High
- Function 4.h, Main Steam Line Tunnel Ambient Temperature-High
- Function 5.a, RHR Equipment Room Ambient Temperature-High

For this function, no revision to TS allowable values or safety analyses results from the required evaluations. The temperature elements are not required to be calibrated, therefore, no drift evaluation was performed. Extending the surveillance test interval for calibration of these functions is acceptable because the functions are verified to be operating properly by the performance of more frequent Channel Checks (i.e., SR 3.3.6.1.1 every 12 hours) and Channel Functional Tests (i.e., SR 3.3.6.1.2 every 92 days). Additionally, each of the above functions is provided with sufficient channels to ensure that no single instrument failure can preclude the isolation function.

The temperature switches associated with these functions were replaced during the previous refueling outage due to poor performance from the previous design switches. Due to the replacement a limited review of the applicable River Bend surveillance history for these channels (channel functional tests only) was performed. This review did not identify any functional failures of the replacement switches. Additionally, the historical failure review for the other loop components did not detect any failures that would have prevented the performance of the safety function. More frequent Channel Functional Tests will identify any channel failures between refueling intervals. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on system design and the history of system performance, the impact of this change on safety, if any, is small.

<u>SR 3.3.6.1.5</u> Perform CHANNEL CALIBRATION.
- Function 2.c, Containment Purge Isolation Radiation-High

For this function, no revision to TS allowable values or safety analyses results from the required evaluations. Drift evaluations were not performed for radiation monitors. The above radiation detectors are calibrated using a calibrated source as an input signal to the detector. The source check is performed by exposing the sensor-converter to a known source in a constant geometry. Source checks of radiation monitors are subject to far more uncertainties than electronic calibration checks because of source decay, positioning of the sources, signal strength, and the sensor response curves of that particular monitoring system. Because of the uncertainties associated with the calibration methods for these devices, any AFAL evaluation would provide no true indication of the instrument performance over time.

Extending the surveillance test interval for calibration of these functions is acceptable because the functions are verified to be operating properly by the performance of more frequent Channel Checks (i.e., SR 3.3.6.1.1 every 12 hours) and Channel Functional Tests (i.e., SR 3.3.6.1.2 every 92 days). Additionally, the above function is provided with two channels, which ensures that no single instrument failure can preclude the isolation function.

A review of the applicable River Bend surveillance history for these channels demonstrated that the as-found trip setpoint for these functions had no previous failures of TS required allowable values that would have been detected solely by the periodic performance of this SR. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on system design and the history of system performance, the impact of this change on safety, if any, is small.

<u>3.3.6.2 Secondary Containment and Fuel Building Isolation Instrumentation</u>

The secondary containment isolation instrumentation automatically initiates closure of appropriate secondary containment isolation dampers (SCIDs) and starts appropriate ventilation subsystems. Similarly, the fuel building isolation instrumentation automatically initiates closure of appropriate fuel building isolation dampers (FBIDs) and initiates fuel building ventilation flow through the filtration system.

<u>SR 3.3.6.2.4</u> Perform CHANNEL CALIBRATION.
- Function 1, Reactor Vessel Water Level-Low Low, Level 2
- Function 2, Drywell Pressure-High

For this function, no revision to TS allowable values or safety analyses result from the GL 91-04 evaluations (e.g., statistical evaluation of historical drift factored into setpoint calculations). Any necessary revisions to setpoint calculations and calibration procedures to incorporate results of the statistical analysis of the historical AFAL data will be completed prior to implementation.

A review of the applicable River Bend surveillance history for these channels demonstrated that the as-found trip setpoint for these functions had no previous failures of TS required allowable values that would have been detected solely by the periodic performance of this SR. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on the history of system performance, the impact of this change on safety, if any, is small.

<u>SR 3.3.6.2.4</u> Perform CHANNEL CALIBRATION.
- Function 3, Fuel Building Ventilation Exhaust Radiation-High(1RMS*RE5A)
- Function 4, Fuel Building Ventilation Exhaust Radiation-High(1RMS*RE5B)

For these functions, no revision to TS allowable values or safety analyses result from the required evaluations. Drift evaluations were not performed for radiation monitors. The above radiation detectors are calibrated using a calibrated source as an input signal to the detector. The source check is performed by exposing the sensor-converter to a known source in a constant geometry. Source checks of radiation monitors are subject to far more uncertainties than electronic calibration checks because of source decay, positioning of the sources, signal strength, and the sensor response curves of that particular monitoring system. Because of the uncertainties associated with the calibration methods for these devices, any AFAL evaluation would provide no true indication of the overall instrument performance over time.

Extending the surveillance test interval for calibration of these functions is acceptable because the functions are verified to be operating properly by the performance of more frequent Channel Checks (i.e., SR 3.3.6.2.1 every 12 hours) and Channel Functional Tests (i.e., SR 3.3.6.2.2 every 92 days). Furthermore, the ongoing drift trend program will monitor these channels for operation within the assumptions of the setpoint analysis.

A review of the applicable River Bend surveillance history for these channels demonstrated that the as-found trip setpoint for these functions had no previous failures of TS required allowable values that would have been detected solely by the periodic performance of this SR. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on system design and the history of system performance, the impact of this change on safety, if any, is small.

3.3.6.3 Containment Unit Cooler System Instrumentation

The primary containment ventilation system consists of three 100% capacity unit coolers, two of which are safety related. In conjunction with the RHR suppression pool cooling mode of operation, the containment ventilation system functions to ensure containment integrity following a LOCA by preventing containment pressures and temperatures in excess of the containment design criteria..

SR 3.3.6.3.4 Perform CHANNEL CALIBRATION.
- Function 1, Drywell Pressure-High
- Function 2, Containment-to-Annulus Differential Pressure-High
- Function 3, Reactor Vessel Water Level – Low Low Low, Level 1
- Function 4, System A and System B Timers,

For these functions, no revision to TS allowable values or safety analyses result from the GL 91-04 evaluations (e.g., statistical evaluation of historical drift factored into setpoint calculations). Any necessary revisions to setpoint calculations and calibration procedures to incorporate results of the statistical analysis of the historical AFAL data will be completed prior to implementation

A review of the applicable River Bend surveillance history for these channels demonstrated that the as-found trip setpoint for all these functions had only one previous failure of a TS required allowable value that would have been detected solely by the periodic performance of this SR.

A failure associated with Function 4 was experienced on 9/11/1999 due to timing relay HVR-A02-62A failing due to signs of overheating. The relay was replaced with a new Agastat Model ETR14D3NC2004003 relay. The identified failure is unique and does not occur on a repetitive basis and is not associated with a time-based failure mechanism.

There are a total of eight Agastat relay failures over the review period. Of the eight Agastat relay failures, four failures were Model EGPI, one was Model EGPD, one was Model ETR14D3N and two were Model ETR14D3G. In all eight Agastat relay failures, the defective relays were replaced. Two of the Agastat Model EGPI failures were in the RHR Equipment Room Ambient Temperature function of the Primary Containment Isolation logic in 2002 and the Main Steam Line Isolation function of the Primary Containment Isolation Logic circuitry in 2007. One of the Agastat Model EGPI failures occurred in 2003 and was in the Compressor C3A Seal Makeup Isolation Valve auto closure circuit and the fourth Agastat EGPI failure occurred in 2008 and was in the DIV I EDG Trip Logic. The Agastat Model EGPD relay failure occurred in 2006 and the relay is utilized in the Reactor Vessel Pressure Low function of the Relief and Low Low Set - Relief Function logic. The Agastat Model ETR14D3N relay failure occurred in 1999 and the relay is utilized in the Containment Unit Cooler System. One Agastat Model ETR14D3G relay failure occurred in 1999 and was in Chiller HVK-CHL1A load sequencing circuit and the second Agastat Model ETR14D3G relay failure occurred in 2000 and was in Chiller HVK-CHL1C load sequencing circuit. There are no time-based mechanisms apparent in these failures. Therefore, this failure is unique and any subsequent failure would not result in a significant impact on system/component availability.

As such, this failure is not indicative of a repetitive failure problem and does not invalidate the conclusion that only on rare occasions do as-found values exceed acceptable limits. Based on the history of system performance, the impact of this change on safety, if any, is small.

3.3.6.4 Relief and Low-Low Set (LLS) Instrumentation

The safety/relief valves (S/RVs) prevent overpressurization of the nuclear steam system. Instrumentation is provided to support two modes (in addition to the automatic depressurization system (ADS) mode of operation for selected valves) of S/RV operation—the relief function (all valves) and the LLS function (selected valves).

SR 3.3.6.4.3 Perform CHANNEL CALIBRATION.
a) Relief Function
b) LLS Function

For these functions, no revision to TS allowable values or safety analyses result from the GL 91-04 evaluations (e.g., statistical evaluation of historical drift factored into setpoint calculations. Any necessary revisions to setpoint calculations and calibration procedures to incorporate results of the statistical analysis of the historical AFAL data will be completed prior to implementation.

A review of the applicable River Bend surveillance history for these channels demonstrated that the as-found trip setpoint for these functions had no previous failures of TS required allowable values that would have been detected solely by the periodic performance of this SR. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on the history of system performance, the impact of this change on safety, if any, is small.

3.3.7.1 Control Room Fresh Air (CRFA) System Instrumentation

The instrumentation and controls for the Control Room Fresh Air (CRFA) System automatically initiate action to isolate or pressurize the main control room (MCR) to minimize the consequences of radioactive material in the control room environment.

SR 3.3.7.1.4 Perform CHANNEL CALIBRATION.

- Function 1, Reactor Vessel Water Level – Low Low, Level 2
- Function 2, Drywell Pressure – high

For these functions, no revision to TS allowable values or safety analyses result from the GL 91-04 evaluations (e.g., statistical evaluation of historical drift factored into setpoint calculations. Any necessary revisions to setpoint calculations and calibration procedures to incorporate results of the statistical analysis of the historical AFAL data will be completed prior to implementation.

A review of the applicable River Bend surveillance history for these channels demonstrated that the as-found trip setpoint for these functions had no previous failures of TS required allowable values that would have been detected solely by the periodic performance of this SR. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on the history of system performance, the impact of this change on safety, if any, is small.

SR 3.3.7.1.4 Perform CHANNEL CALIBRATION.

- Function 3, Control Room Local Intake Ventilation Radiation Monitors

For this function, no revision to TS allowable values or safety analyses result from the required evaluations. Drift evaluations were not performed for radiation monitors. These 2 radiation detectors are calibrated using a calibrated source as an input signal to the detector. The source check is performed by exposing the sensor-converter to a known source in a constant geometry. Source checks of radiation monitors are subject to far more uncertainties than electronic calibration checks because of source decay, positioning of the sources, signal strength, and the sensor response curves of that particular monitoring system. Because of the uncertainties associated with the calibration methods for these devices, any AFAL evaluation would provide no true indication of the instrument performance over time.

Extending the surveillance test interval for calibration of these functions is acceptable because the functions are verified to be operating properly by the performance of more frequent Channel Checks (i.e., SR 3.3.7.1.1 every 12 hours) and Channel Functional Tests (i.e., SR 3.3.7.1.2 every 92 days). The Control Room Local Intake Ventilation Radiation Monitors Function consists of two independent monitors. Two channels of Control Room Local Intake Ventilation Radiation Monitors are available and are required to be OPERABLE to ensure that no single instrument failure can preclude CRFA System initiation. Furthermore, the ongoing drift trend program will monitor these channels for operation within the assumptions of the setpoint analysis.

A review of the applicable River Bend surveillance history for these channels demonstrated that the as-found trip setpoint for these functions had no previous failures of TS required allowable values that would have been detected solely by the periodic performance of this SR. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on system design and the history of system performance, the impact of this change on safety, if any, is small.

3.3.8.1 Loss of Power (LOP) Instrumentation

Successful operation of the required safety functions of the Emergency Core Cooling Systems (ECCS) is dependent upon the availability of adequate power sources for energizing the various components such as pump motors, motor operated valves, and the associated control components. The LOP instrumentation monitors the 4.16 kV emergency buses. Offsite power is the preferred source of power for the 4.16 kV emergency buses. If the monitors determine that insufficient power is available, the buses are disconnected from the offsite power sources and connected to the onsite diesel generator (DG) power sources.

SR 3.3.8.1.3 Perform CHANNEL CALIBRATION.

- Function 1.a, Division 1 and 2 – 4.16 kV Emergency Bus Undervoltage - Loss of Voltage – 4.16 kV basis
- Function 1.b, Division 1 and 2 – 4.16 kV Emergency Bus Undervoltage - Loss of Voltage - Time Delay
- Function 1.c, Division 1 and 2 – 4.16 kV Emergency Bus Undervoltage - Degraded Voltage - 4.16 kV basis
- Function 1.d, Division 1 and 2 – 4.16 kV Emergency Bus Undervoltage - Degraded Voltage – Time Delay, No LOCA
- Function 1.e, Division 1 and 2 – 4.16 kV Emergency Bus Undervoltage - Degraded Voltage - Time Delay, LOCA
- Function 2.a, Division 3 - 4.16 kV Emergency Bus Undervoltage - Loss of Voltage – 4.16 kV basis
- Function 2.b, Division 3 - 4.16 kV Emergency Bus Undervoltage - Loss of Voltage - Time Delay
- Function 2.c, Division 3 - 4.16 kV Emergency Bus Undervoltage - Degraded Voltage – 4.16 kV basis
- Function 2.d, Division 3 - 4.16 kV Emergency Bus Undervoltage - Degraded Voltage – Time Delay, No LOCA
- Function 2.e, Division 3 - 4.16 kV Emergency Bus Undervoltage - Degraded Voltage - Time Delay, LOCA

The results of the drift analysis indicated that the projected 30 month drift values for the instruments Division 1 and 2 -4.16 kV emergency Bus Undervoltage –Degraded Voltage-4.16 kV (Table 3.3.8.1-1, Function 1.c) and Division 3 -4.16 kV emergency Bus Undervoltage –Degraded Voltage-4.16 kV (Table 3.3.8.1-1, Function 2.c) exceeded the drift allowance provided in the setpoint calculation for these functions and were outside the Technical Specification Allowable Values. The calculation will be revised to verify that the Allowable Values can be extended and a new setpoint will been defined in this calculation. The Allowable Value for Item 1.c will be changed from ≥ 3689 V and ≤ 3835.2V to ≥ 3760.4 V and ≤ 3795.5V. The Allowable Value for Item 2.c will be changed from ≥ 3674.0 V and ≤ 3721.2V to ≥ 3754.5 V and ≤ 3792.6V. Since the current plant setpoints for both of these functions will not be conservative for this change, the new calculated nominal trip setpoints will be revised in the Technical Requirements Manual using the 50.59 process.

RBS proposes to maintain the existing setpoints and Allowable Values until after NRC approval of the license amendment. RBS condition reports identified concerns with Electrical Design Basis calculations as a result of the NRC Component Design Basis Inspection in 2008. Of primary concern was the ability of the GL 89-10 MOV's to perform their design basis function at degraded grid voltage concurrent with a LOCA. An operability determination was performed and documented in accordance with the RBS corrective action program. Because all Class 1E motors were purchased to be capable of starting and accelerating their driven equipment with motor terminal voltages of 70 or 80 percent of motor nameplate voltage without affecting performance or equipment life, no operability concerns existed for any equipment. However, a group of the motor operated valves governed by GL 89-10 was determined to have insufficient voltage to pick up their torque switch thus allowing potential failure after reaching their safety position. Thus, although the valves maintain their operability, full functionality is not maintained under current analysis. To bring the valves back to full functionality, RBS will use the results of the offsite grid stability studies to increase the Allowable Value and trip setpoints of the Division 1 and 2 -4.16 kV emergency Bus Undervoltage –Degraded Voltage-4.16 kV Basis (Table 3.3.8.1-1, Function 1.c) and Division 3 -4.16 kV emergency Bus Undervoltage –Degraded Voltage-4.16 kV Basis (Table 3.3.8.1-1, Function 2.c)

The purpose of this proposed Technical Specification Change is to define new Allowable Values in the RBS Technical Specification Table 3.3.8.1-1 for function 1.c and 2.c to address both the effect of 30 month drift uncertainty on the Degraded Voltage Setpoints as well as restoring full function to all GL 89-10 valves. The proposed Allowable Value changes have no impact on current RBS Table 3.3.8.1-1 for functions 1.a, 1.b,1.d,1.e, 2.a, 2.b, 2.d or 2.e setpoints or trip logic. It is the intent in establishing the new AV's that the current design and licensing basis for the settings as reflected in RBS Technical Specification Bases description B.3.3.8.1 not be changed. In maintaining current design and licensing basis, the subject Allowable Value changes are being made utilizing current LOCA Response Voltage analysis, the setpoint methodology consistent with current industry standards, and evaluated 30 month drift uncertainty for the Degraded Voltage relays.

<u>Background (Design and Licensing Basis of AV)</u>

Branch Technical Position (BTP) PSB-1 requires that a second level of undervoltage protection, in addition to Loss-of-Voltage protection be provided to protect safety related equipment from sustained operation at degraded voltage levels which might affect equipment operability. Accordingly, an Analytical Limit is established based on the maximum bus voltage recovery time during a LOCA response relative to electrical component (e.g. motors) sequencing and acceleration when loaded on the bus. The under-voltage protection scheme at River Bend consists of two levels of protection for Class 1E equipment. The first level is set at approximately 70% of nominal bus voltage with a time delay of three seconds. Following this delay the Class 1E distribution system is automatically separated from the offsite power system.

The second level of under-voltage protection is designed to actuate when grid voltages fall below the lowest expected value, which maintains an emergency bus voltage greater than minimum necessary for Class 1E equipment function. Each divisional 4160 V safety related bus has a dedicated circuit consisting of relays arranged in a 2-out-of-3 coincidence logic with two time delays each. The two separate time delays are for low voltage protection during two conditions of operation: with and without a LOCA occurrence. The first time delay is approximately 5 seconds to accommodate normal motor starting transients. Following this delay, an alarm in the main control room alerts the operator to the degraded condition. An occurrence of a LOCA signal subsequent to this degraded voltage condition immediately separates the Class 1E 4160 V safety related bus from the offsite power system. The second time delay is approximately 60 seconds. After this delay, if the operator has failed to restore adequate voltages, the Class 1E 4160 V safety related bus is automatically separated from the offsite power system, irrespective of the occurrence of a LOCA.

The River Bend Station Division 1 4160 V safety related bus is fed directly from preferred transformer RTX-XSR1C and the Division 2 4160 V safety related bus is fed directly from preferred transformer RTX-XSR1D. A non-safety 4160 V bus is also fed from each of these preferred transformers. In turn, a third non-safety 4160 V bus can be fed from either of the upstream non-safety 4160 V buses.

Technical Specification Bases criteria for the Degraded Voltage instrumentation requires: 1) the Degraded Voltage Allowable Values to be low enough to prevent inadvertent power supply transfer, but high enough to ensure that sufficient voltage is available to the required equipment; and 2) the Time Delay Allowable Values to be long enough to provide time for the offsite power supply to recover to normal voltages, but short enough to ensure that sufficient power is available to the required equipment.

Generic Letter (GL) 89-10 MOVs are required to perform their design basis function at degraded grid voltage concurrent with a LOCA. An existing operability determination, performed and documented in accordance with the RBS corrective action program, addresses a portion of the GL 89-10 population. Because all Class 1E motors were purchased to be capable of starting and accelerating their driven equipment with motor terminal voltages of 70 or 80 percent of motor nameplate voltage without affecting performance or equipment life, no operability concerns exist for any equipment. However, a group of the motor operated valves governed by GL 89-10 was determined to have insufficient voltage to pick up their torque switch, allowing potential failure after reaching their safety position. Thus, although the valves maintain their operability, full functionality is not maintained under current analysis. To bring the valves back to full functionality, RBS will use the results of the offsite grid stability studies to increase the AV and trip setpoints.

RBS has completed offsite grid stability studies which indicate grid voltage levels remain above 99.5% per unit. RBS will initiate a change to offsite power requirements to ensure that grid voltage is no lower than 97.5% per unit, up from the current limit of 95% per unit. This change will result in an increase in minimum grid voltage Operability limit from 95% per unit to 97.5% per unit and a new MCR alarm set point for Low Grid Voltage of 98.2%, up from 98%.

For these functions, the TS allowable values require revisions however, no revision of the safety analyses resulted from the GL 91-04 evaluations (e.g., statistical evaluation of historical drift factored into setpoint calculations).

A review of the applicable River Bend surveillance history for these channels demonstrated that the as-found trip setpoint for these functions had only two previous failures of TS required allowable values that would have been detected solely by the periodic performance of this SR.

On September 19, 1997, a timer relay associated with SR 3.3.8.1.3, Functions 1.c, 1.d and 1.e had contacts which did not change state when the timer timed out. The relay was replaced with an ABB Model ITE-62K relay and tested satisfactorily. The identified failure is unique and does not occur on a repetitive basis and is not associated with a time-based failure mechanism.

On October 31, 2004, a timer relay associated with SR 3.3.8.1.3, Functions 1.e failed its time delay criteria. The relay's time delay could not be adjusted within the acceptable range. The relay was replaced with an ABB Model ITE-27N relay and tested satisfactorily. Subsequent evaluation concluded the relay time delay was off in the conservative direction, and therefore, the protection scheme was more subject to false actuation. It would have operated to perform its protective function. The identified failure is unique and does not occur on a repetitive basis and is not associated with a time-based failure mechanism.

There are a total of two failures identified over the review period relative to ASEA Brown Boveri relays. One failure was Model ITE-62K and one failure was Model ITE-27H. In both cases, the defective relays were replaced. Both failures were in the 4.16 kV Emergency Bus Undervoltage/Degraded Voltage function of the Loss of Power Instrumentation. There are no time-based mechanisms apparent in these failures. Therefore, each failure is unique and any subsequent failure would not result in a significant impact on system/component availability As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on the history of system performance, the impact of this change on safety, if any, is small.

3.3.8.2 Reactor Protection System (RPS) Electric Power Monitoring

The RPS Electric Power Monitoring System is provided to isolate the RPS bus from the motor generator (MG) set or alternate power supply in the event of overvoltage, undervoltage, or underfrequency. This system protects the loads connected to the RPS bus against unacceptable voltage and frequency conditions.

SR 3.3.8.2.2 Perform CHANNEL CALIBRATION.
- Function a, Overvoltage
- Function b, Undervoltage
- Function c, Underfrequency(with time delay set to ≤ 4.0 seconds)

For these functions, no revision to TS allowable values or safety analyses result from the required evaluations. Any necessary revisions to setpoint calculations and calibration procedures will be completed prior to implementation.

A review of the applicable River Bend surveillance history for these channels demonstrated that the as-found trip setpoint for these functions had no previous failures of TS required allowable values that would have been detected solely by the periodic performance of this SR. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on the history of system performance, the impact of this change on safety, if any, is small.

3.4.7 RCS Leakage Detection Instrumentation

Leakage detection systems for the RCS are provided to alert the operators when leakage rates above normal background levels are detected and to supply quantitative measurement of rates.

SR 3.4.7.3 Perform CHANNEL CALIBRATION of required leakage detection instrumentation.

For this function, no revision to TS allowable values or safety analyses results from the required evaluations. Drift evaluations were not performed for these instruments.

No allowable value is applicable to these functions. The leakage detection instrumentation differs from other TS instruments in that they are not associated with a function trip, but indication only to the control room operator. As such, these instruments are not expected to function with the same high degree of accuracy demanded of functions with assumed trip actuations for accident detection and mitigation. The leakage detection instrumentation devices are expected to maintain sufficient accuracy to detect trends or the existence or non-existence of an excessive leakage condition.

The surveillance test interval of this SR is being increased from once every 18 months to once every 24 months, for a maximum interval of 30 months including the 25% grace period. The drywell and pedestal floor drain sump flow monitoring systems are required to quantify the unidentified leakage from the RCS. The drywell and pedestal floor drain sump fill rate and pump turn-on and off times are monitored by a programmable controller to activate an alarm in the main control room when the leak rate reaches a preset value. The other monitoring systems provide qualitative indication to the operators so closer examination of other detection systems will be made to determine the extent of any corrective action that may be required. More frequent verification of the instrument functions are accomplished by SR 3.4.7.1 (Channel Check of the required drywell atmospheric monitoring system) once every 12 hours and SR 3.4.7.2 (Channel Functional Tests of the required leakage detection instrumentation) once every 31 days.

A review of the applicable River Bend surveillance history demonstrated that the RCS Leakage Detection System had no previous failures of the TS function that would have been detected solely by the periodic performance of this SR. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Based on the redundancy of detection methods, other more frequent testing of the system, and the history of system performance, the impact of this change on safety, if any, is small.

Attachment 6
RBG-46932

Detailed Evaluation Methods

Entergy

ENTERGY NUCLEAR
Engineering Report Cover Sheet

Engineering Report Title:

Instrument Drift Analysis
Design Guide

Engineering Report Type:

New ☒ Revision ☐ Cancelled ☐ Superseded ☐

Applicable Site(s)

IP1	☐	IP2	☐	IP3	☐	JAF	☐	PNPS	☐	VY	☐	WPO	☐
ANO1	☐	ANO2	☐	ECH	☐	GGNS	☒	RBS	☒	WF3	☐	PLP	☐

DRN No. ☐N/A; ☐____

(5) **Report Origin:** ☐ Entergy ☒ Vendor

Vendor Document No.:__________

(6) **Quality-Related:** ☒ Yes ☐ No

Prepared by: Kirk R. Melson / Kirk R. Melson Date: 7/23/08
Responsible Engineer (Print Name/Sign)

Design Verified: Jerry D. Voss / Jerry D Voss Date: 7/23/08
Design Verifier (if required) (Print Name/Sign)

Reviewed by: N/A Date: ________
Reviewer (Print Name/Sign)

Reviewed by: N/A Date: ________
Reviewer (Print Name/Sign)

Reviewed by*: N/A Date: ________
ANII (if required) (Print Name/Sign)

Approved by: N/A Date: ________
Supervisor (Print Name/Sign)

*: For ASME Section XI Code Program plans per ENN-DC-120, if required

RECOMMENDATION FOR APPROVAL FORM

Site	Verifier/Reviewer (Print Name/Sign)	Date	Responsible Supervisor (Print Name/Sign)	Date
ANO1				
ANO2				
ECH				
GGNS				
IP1				
IP2				
IP3				
JAF				
PLP				
PNPS				
RBS				
VY				
WF3				
WPO				

TABLE OF CONTENTS

TABLES PAGE

Record of Revision

Rev. No.	Description
0	Initial Issue

1. OBJECTIVE/PURPOSE

The objective of this Design Guide is to provide the necessary detail and guidance to perform drift analyses using past calibration history data for the purposes of:

- Quantifying component/loop drift characteristics within defined probability limits to gain an understanding of the expected behavior for the component/loop by evaluating past performance
- Estimating component/loop drift for integration into setpoint calculations
- Analysis aid for reliability centered maintenance practices (e.g., optimizing calibration frequency)
- Establishing a technical basis for extending calibration and surveillance intervals using historical calibration data
- Trending device performance based on extended surveillance intervals

2. DRIFT ANALYSIS SCOPE

The scope of this design guide is limited to the calculation of the expected performance for a component, group of components or loop, utilizing past calibration data. Drift Calculations are the final product of the data analysis. The output from the Drift Calculations may be used directly as input to setpoint or loop accuracy calculations. However, if desired, the output may be compared to the design values used within setpoint and loop accuracy calculations to show that the existing design approach is conservative.

The approaches described within this design guide can be applied to all devices that are surveilled or calibrated where As-Found and As-Left data is recorded. The scope of this design guide includes, but is not limited to, the following list of devices:

- Transmitters (Differential Pressure, Flow, Level, Pressure, Temperature, etc.)
- Bistables (Master & Slave Trip Units, Alarm Units, etc.)
- Indicators (Analog, Digital)
- Switches (Differential Pressure, Flow, Level, Position, Pressure, Temperature, etc.)
- Signal Conditioners/Converters (Summers, E/P Converters, Square Root Converters, etc.)
- Recorders (Temperature, Pressure, Flow, Level, etc.)
- Monitors & Modules (Radiation, Neutron, H_2O_2, Pre-Amplifiers, etc.)
- Relays (Time Delay, Undervoltage, Overvoltage, etc.)

Note that a given device or device type may be justified not to require drift analysis in accordance with this design guide, if appropriate.

3. DISCUSSION/METHODOLOGY

3.1. Methodology Options

This design guide is written to provide the methodology necessary for the analysis of As-Found versus As-Left calibration data, as a means of characterizing the performance of a component or group of components via the following methods:

3.1.1. Electric Power Research Institute (EPRI) has developed a guideline to provide nuclear plants with practical methods for analyzing historic component calibration data to predict component performance via a simple spreadsheet program (e.g., Excel, Lotus 1-2-3). This design guide is written in close adherence to this guideline, Reference 7.1.1. The Nuclear Regulatory Commission reviewed Revision 0 of Reference 7.1.1 and had a list of concerns documented in Reference 7.1.8. These concerns prompted the issuance of Revision 1 to Reference 7.1.1. In addition, Appendix A to this design guide addresses each concern individually and provides the River Bend Station (RBS) and Grand Gulf Nuclear Station (GGNS) resolution.

3.1.2. Commercial Grade Software programs other than Microsoft Excel (e.g. IPASS, Lotus 1-2-3, SYSTAT, etc.), that perform the functions necessary to evaluate drift, may be utilized providing:

- the intent of this design guide is met as outlined in Reference 7.1.1, and
- software is used only as a tool to produce hard copy outputs which are to be independently verified.

3.1.3. The EPRI IPASS software, version 2.03, may be used to perform or independently verify certain portions of the drift analysis. The IPASS software does not have the functionality to perform many of the functions required by the drift analysis, such as certain time dependency functions, and therefore, should only be used in conjunction with other software products to produce or verify an entire Drift Calculation.

3.1.4. The final products of the data analyses are hard copy Drift Calculations. The electronic files of the Drift Calculations are an intermediate step from raw data to final product and are not controlled as QA files. The Drift Calculation is independently verified using different software than that used to create the Drift Calculation. The documentation of the review of the Drift Calculation will include a summary tabulation of results from each program used in the review process to provide visual evidence of the acceptability of the results of the review.

3.2. Data Analysis Discussion

The following data analysis methods were evaluated for use at RBS and GGNS: 1) As-Found Versus Setpoint, 2) Worst Case As-Found Versus As-Left, 3) Combined Calibration Data Points Analysis, and 4) As-Found Versus As-Left. The evaluation concluded that the As-Found versus As-Left methodology provided results that were more representative of the data and has been chosen for use by this Design Guide. Statistical tests not covered by this design guide may be utilized, provided the Engineer performing the analysis adequately justifies the use of the tests.

3.2.1. As-Found Versus As-Left Calibration Data Analysis

The As-Found versus As-Left calibration data analysis is based on calculating drift by subtracting the previous As-Left component setting from the current As-Found setting. Each calibration point is treated as an independent set of data for purposes of characterizing drift across the full, calibrated span of the component/loop. By evaluating As-Found versus As-Left data for a component/loop or a similar group of components/loops, the following information may be obtained:

- The typical component/loop drift between calibrations (Random in nature)
- Any tendency for the component/loop to drift in a particular direction (Bias)

- Any tendency for the component/loop drift to increase in magnitude over time (Time Dependency)
- Confirmation that the selected setting or calibration tolerance is appropriate or achievable for the component/loop

3.2.1.1. General Features of As-Found Versus As-Left Analysis

- The methodology evaluates historical calibration data only. The method does not monitor on-line component output; data is obtained from component calibration records.
- Present and future performance is predicted based on statistical analysis of past performance.
- Data is readily available from component calibration records. Data can be analyzed from plant startup to the present or only more recent data can be evaluated.
- Since only historical data is evaluated, the method is not intended as a tool to identify individual faulty components, although it can be used to demonstrate that a particular component model or application historically performs poorly.
- A similar class of components, i.e., same make, model, or application, is evaluated. For example, the method can determine the drift of all analog indicators of a certain type installed in the control room.
- The methodology is less suitable for evaluating the drift of a single component over time, due to statistical analysis penalties that occur with smaller sample sizes.
- The methodology obtains a value of drift for a particular model, loop, or function that can be used in component or loop uncertainty and setpoint calculations.
- The methodology is designed to support the analysis of longer calibration intervals and is consistent with the NRC expectations described in Reference 7.3.3. Values for instrument drift developed in accordance with this Design Guide are to be applied in accordance with References 7.2.1 and 7.2.2, as appropriate.

3.2.1.2. Error and Uncertainty Content in As-Found Versus As-Left Calibration Data

The As-Found versus the As-Left data includes several sources of uncertainty over and above component drift. The difference between As-Found and previous As-Left data encompasses a number of instrument uncertainty terms in addition to drift, as defined by References 7.2.1 and 7.2.2, the setpoint calculation methodologies for RBS and GGNS. The drift is <u>not</u> assumed to encompass the errors associated with temperature effect, since the temperature difference between the two calibrations is not quantified, and is not anticipated to be significant. Additional instruction for the use of As-Found and As-Left data may be found in Reference 7.1.2. The following possible contributors could be included within the measured variation, but are not necessarily considered as such.

- Accuracy errors present between any two consecutive calibrations
- Measurement and test equipment error between any two consecutive calibrations
- Personnel-induced or human-related variation or error between any two consecutive calibrations
- Normal temperature effects due to a difference in ambient temperature between

any two consecutive calibrations

- Power Supply variations between any two consecutive calibrations
- Environmental effects on component performance, e.g., radiation, humidity, vibration, etc., between any two consecutive calibrations that cause a shift in component output
- Misapplication, improper installation, or other operating effects that affect component calibration between any two consecutive calibrations
- True drift representing a change, time-dependent or otherwise, in component/loop output over the time period between any two consecutive calibrations

3.2.1.3. Potential Impacts of As-Found Versus As-Left Data Analysis

Many of the bulleted items listed in step 3.2.1.2 are not expected to have a significant effect on the measured As-Found and As-Left settings. Because there are so many independent parameters contributing to the possible variance in calibration data, they are all considered together and termed the component's Analyzed Drift (DA) uncertainty. This approach has the following potential impacts on an analysis of the component's calibration data:

- The magnitude of the calculated variation may exceed any assumptions or manufacturer predictions regarding drift. Attempts to validate manufacturer's performance claims should consider the possible contributors listed in step 3.2.1.2 to the calculated drift.

- The magnitude of the calculated variation that includes all of the above sources of uncertainty may mask any "true" time-dependent drift. In other words, the analysis of As-Found versus As-Left data may not demonstrate any time dependency. This does not mean that time-dependent drift does not exist, only that it could be so small that it is negligible in the cumulative effects of component uncertainty, when all of the above sources of uncertainty are combined.

3.3. Confidence Interval

This Design Guide recommends a single confidence interval level to be used for performing data analyses and the associated calculations.

NOTE: The default Tolerance Interval Factor (TIF) for all Drift Calculations, performed using this Design Guide, is chosen for a 95%/95% probability and confidence, although this is not specifically required in every situation. This term means that the results have a 95% confidence (γ) that at least 95% of the population lies between the stated interval (P) for a sample size (n). Components that perform functions that support a specific Technical Specification value, Technical Requirements Manual (TRM) value or are associated with the safety analysis assumptions or inputs are always analyzed at a 95%/95% confidence interval. Components/loops that fall into this level must:

- be included in the data group (or be justified to apply the results per the guidance of Reference 7.1.1) if the analyzed drift value is to be applied to the component/loop in a Setpoint/Uncertainty Calculation,
- use the 95/95% TIF for determination of the Analyzed Drift term, and (see step 3.4.2 and Table 1 – 95%/95%Tolerance Interval Factors)
- be evaluated in the Setpoint/Uncertainty Calculation for application of the Analyzed Drift term. (For example, the DA term may include the normal temperature effects for a given device, but due to the impossibility of separating out that specific term, an additional temperature uncertainty may be included in the Setpoint/Uncertainty Calculation.)

3.4. Calibration Data Collection

3.4.1. Sources of Data

The sources of data to perform a drift analysis are Surveillance Tests, Calibration Procedures and other calibration processes (calibration files, calibration sheets for Balance of Plant devices, Preventative Maintenance, etc.).

3.4.2. How Much Data to Collect

3.4.2.1. The goal is to collect enough data for the instrument or group of instruments to make a statistically valid pool. There is no hard fast number that must be attained for any given pool, but a minimum of 30 drift values must be attained before the drift analysis can be performed without additional justification. As a general rule, drift analyses should not be performed for sample sizes of less than 20 drift values. Table 1 provides the 95%/95% TIF for various sample pool sizes; it should be noted that the smaller the pool the larger the penalty. A tolerance interval is a statement of confidence that a certain proportion of the total population is contained within a defined set of bounds. For example, a 95%/95% TIF indicates a 95% level of confidence that 95% of the population is contained within the stated interval.

Table 1 – 95%/95%Tolerance Interval Factors

Sample Size	95%/95%	Sample Size	95%/95%	Sample Size	95%/95%
≥ 2	37.674	≥ 23	2.673	≥ 120	2.205
≥ 3	9.916	≥ 24	2.651	≥ 130	2.194
≥ 4	6.370	≥ 25	2.631	≥ 140	2.184
≥ 5	5.079	≥ 26	2.612	≥ 150	2.175
≥ 6	4.414	≥ 27	2.595	≥ 160	2.167
≥ 7	4.007	≥ 30	2.549	≥ 170	2.160
≥ 8	3.732	≥ 35	2.490	≥ 180	2.154
≥ 9	3.532	≥ 40	2.445	≥ 190	2.148
≥ 10	3.379	≥ 45	2.408	≥ 200	2.143
≥ 11	3.259	≥ 50	2.379	≥ 250	2.121
≥ 12	3.162	≥ 55	2.354	≥ 300	2.106
≥ 13	3.081	≥ 60	2.333	≥ 400	2.084
≥ 14	3.012	≥ 65	2.315	≥ 500	2.070
≥ 15	2.954	≥ 70	2.299	≥ 600	2.060
≥ 16	2.903	≥ 75	2.285	≥ 700	2.052
≥ 17	2.858	≥ 80	2.272	≥ 800	2.046
≥ 18	2.819	≥ 85	2.261	≥ 900	2.040
≥ 19	2.784	≥ 90	2.251	1000	2.036
≥ 20	2.752	≥ 95	2.241	∞	1.960
≥ 21	2.723	≥ 100	2.233		
≥ 22	2.697	≥ 110	2.218		

3.4.2.2. Different information may be needed, depending on the analysis purpose, therefore, the total population of components - all makes, models, and applications that are to be analyzed must be known (e.g., all Rosemount transmitters).

3.4.2.3. Once the total population of components is known, the components should be separated into functionally equivalent groups. Each grouping is treated as a separate population for analysis purposes. (e.g., starting with all Rosemount Differential Pressure Transmitters as the initial group and breaking them down into various sub-groups - Different Range Codes, Large vs. Small Turn Down Factors, Level vs. Flow Applications, etc.).

3.4.2.4. Not all components or available calibration data points need to be analyzed within each group in order to establish statistical performance limits for the group. Acquisition of data should be considered from different perspectives.

- For each grouping, a large enough sample of components should be randomly selected from the population, so there is assurance that the evaluated components are representative of the entire population. By randomly selecting the components and confirming that the behavior of the randomly selected components is similar, a basis for not evaluating the entire population can be established. For sensors, a random sample from the population should include representation of all desired component spans and functions.
- For each selected component in the sample, enough historic calibration data should be provided to ensure that the component's performance over time is understood.
- Due to the difficulty of determining the total sample set, developing specific sampling criteria is difficult. A sampling method must be used which ensures that various instruments calibrated at different frequencies are included. The sampling method must also ensure that the different component types, operating conditions and other influences on drift are included. Because of the difficulty in developing a valid sampling program, it is often simpler to evaluate all available data for the required instrumentation within the chosen time period. This eliminates changing sample methods, should groups be combined or split, based on plant conditions or performance. For the purposes of this guide, specific justification in the Drift Calculation is required to document any sampling plan.

3.5. Categorizing Calibration Data

3.5.1. Grouping Calibration Data

One analysis goal should be to combine functionally equivalent components (components with similar design and performance characteristics) into a single group. In some cases, all components of a particular manufacturer make and model can be combined into a single sample. In other cases, virtually no grouping of data beyond a particular component make, model, and specific span or application may be possible. Some examples of possible groupings include, but are not limited to, the following:

3.5.1.1. Small Groupings

- All devices of same manufacturer, model and range, covered by the same Surveillance Test
- All trip units used to monitor a specific parameter (assuming that all trip units are the same manufacturer, model and range)

3.5.1.2. Larger Groupings

- All transmitters of a specific manufacturer, model that have similar spans and performance requirements
- All Foxboro Spec 200 isolators with functionally equivalent model numbers
- All control room analog indicators of a specific manufacturer and model

3.5.2. Rationale for Grouping Components into a Larger Sample

- A single component analysis may result in too few data points to make statistically meaningful performance predictions.
- Smaller sample sizes associated with a single component may unduly penalize performance predictions by applying a larger TIF to account for the smaller data set. Larger sample sizes reflect a greater understanding and assurance of representative data that in turn, reduces the uncertainty factor.
- Large groupings of components into a sample set for a single population ultimately allows the user to state the plant-specific performance for a particular make and model of component. For example, the user may state, "Main Steam Flow Transmitters have historically drifted by less than 1%", or "All control room indicators of a particular make and model have historically drifted by less than 1.5%".
- An analysis of smaller sample sizes is more likely to be influenced by non-representative variations of a single component (outliers).
- Grouping similar components together, rather than analyzing them separately, is more efficient and minimizes the number of separate calculations that must be maintained.

3.5.3. Considerations When Combining Components into a Single Group

Grouping components together into a sample set for a single population does not have to become a complicated effort. Most components can be categorized readily into the appropriate population. Consider the following guidelines when grouping functionally equivalent components together.

- If performed on a type-of-component basis, component groupings should usually be established down to the manufacturer make and model, as a minimum. For example, data from Rosemount and Foxboro transmitters should not be combined in the same drift analysis. The principles of operation are different for the various manufacturers, and combining the data could mask some trend for one type of component. This said; it might be desirable to combine groups of components for certain calculations. If dissimilar component types are combined, a separate analysis of each component type should still be completed to ensure analysis results of the mixed population are not misinterpreted or misapplied.
- Sensors of the same manufacturer make and model, but with different calibrated spans or elevated zero points, can possibly still be combined into a single group. For example, a single analysis that determines the drift for all Rosemount pressure transmitters installed onsite might simplify the application of the results. Note that some manufacturers provide a predicted accuracy and drift value for a given component model, regardless of its span. However, the validity of combining components with a variation of span, ranging from tens of pounds to several thousand pounds, should be confirmed. As part of the analysis, the performance of components within each span should be compared to the performance of the other devices to determine if any differences are evident between components with different spans.

- Components combined into a single group should be exposed to similar calibration or surveillance conditions, as applicable. Note that the term operating condition was not used in this case. Although it is desirable that the grouped components perform similar functions, the method by which the data is obtained for this analysis is also significant. If half the components are calibrated in the summer at 90°F and the other half in the winter at 40°F, a difference in observed drift between the data for the two sets of components might exist. In many cases, ambient temperature variations are not expected to have a large effect, since the components are located in environmentally controlled areas.

3.5.4. Verification That Data Grouping Is Appropriate

- Combining functionally equivalent components into a single group for analysis purposes may simplify the scope of work; however, some level of verification should be performed to confirm that the selected component grouping is appropriate. As an example, the manufacturer may claim the same accuracy and drift specifications for two components of the same model, but with different ranges, e.g., 0-5 PSIG and 0-3000 PSIG. However, in actual application, components of one range may perform differently than components of another range.
- Standard statistics texts provide methods that can be used to determine if data from similar types of components can be pooled into a single group. If different groups of components have essentially equal variances and means at the desired statistical level, the data for the groups can be pooled into a single group.
- When evaluating groupings, care must be taken not to split instrument groups only because they are calibrated on a different time frequency. Differences in variances may be indicative of a time dependent component to the device drift. The separation of these groups may mask a time-dependency for the component drift.
- A t-Test (two samples assuming unequal variances) should also be performed on the proposed components to be grouped. The t-Test returns the probability associated with a Student's t-Test to determine whether two samples are likely to have come from the same two underlying populations that have unequal variances. If for example, the proposed group contains 5 sub-groups, the t-Tests should be performed on all possible combinations for the groupings. However, if there is no plausible engineering explanation for the two sets of data being incompatible, the groups should be combined, despite the results of the t-Test. The following formula is used to determine the test statistic value t.

$$t' = \frac{\bar{x}_1 - \bar{x}_2 - \Delta_0}{\sqrt{\frac{s_1^2}{n_1} + \frac{s_2^2}{n_2}}}$$ (Ref. 7.3.4)

Where ;

t' - test statistic

n - Total number of data points

x - Mean of the samples

s^2 - Pooled variance

Δ_0 - Hypothesized mean difference

The following formula is used to estimate the degrees of freedom (df) for the test statistic.

$$df = \frac{\left(\frac{s_1^2}{n_1} + \frac{s_2^2}{n_2}\right)^2}{\frac{\left(\frac{s_1^2}{n_1}\right)^2}{n_1 - 1} + \frac{\left(\frac{s_2^2}{n_2}\right)^2}{n_2 - 1}}$$

Where;

Values are as previously defined.

3.5.5. Examples of Proven Groupings:

- All control room indicators receiving a 4-20mAdc (or 1-5Vdc) signal. Notice that a combined grouping may be possible even though the indicators have different indication spans. For example, a 12 mAdc signal should move the indicator pointer to the 50% of span position on each indicator scale, regardless of the span indicated on the face plate (exceptions are non-linear meter scales).
- All control room bistables of similar make or model tested quarterly for Technical Specification surveillance. Note that this assumes that all bistables are tested in a similar manner and have the same input range, e.g., a 1-5Vdc or 4-20mAdc spans.
- A specific type of pressure transmitter used for similar applications in the plant in which the operating and calibration environment does not vary significantly between applications or location.
- A group of transmitters of the same make and model, but with different spans, given that a review confirms that the transmitters of different spans have similar performance characteristics.

3.5.6. Using Data from Other Nuclear Power Plants:

- It is acceptable, although not recommended, to pool RBS or GGNS specific data with data obtained from other nuclear power plants, providing the data can be verified to be of high quality. In this case the data must also be verified to be acceptable for grouping. Acceptability may be defined by verification of grouping, and an evaluation of calibration procedure methods, Measurement and Test Equipment used, and defined setting tolerances. Where there is agreement in calibration method (for instance, starting at zero increasing to 100 percent and decreasing to zero, taking data every 25%), calibration equipment, and area environment (if performance is affected by the temperature), there is a good possibility that the groups may be combined. Previously collected industry data may not have sufficient information about the manner of collection to allow combination with plant specific data.

3.6. Outlier Analysis

An outlier is a data point significantly different in value from the rest of the sample. The presence of an outlier or multiple outliers in the sample of component or group data may result in the calculation of a larger than expected sample standard deviation and tolerance interval. Calibration data can contain outliers for several reasons. Outlier analyses can be used in the initial analysis process to help to identify problems with data that require correction. Examples include:

- *Data Transcription Errors* - Calibration data can be recorded incorrectly either on the original calibration data sheet or in the spreadsheet program used to analyze the data.
- *Calibration Errors* - Improper setting of a device at the time of calibration would indicate larger than normal drift during the subsequent calibration.
- *Measuring & Test Equipment Errors* - Improperly selected or mis-calibrated test equipment could indicate drift, when little or no drift was actually present.
- *Scaling or Setpoint Changes* - Changes in scaling or setpoints can appear in the data as larger than actual drift points unless the change is detected during the data entry or screening process.
- *Failed Instruments* - Calibrations are occasionally performed to verify proper operation due to erratic indications, spurious alarms, etc. These calibrations may be indicative of component failure (not drift), which would introduce errors that are not representative of the device performance during routine conditions.
- *Design or Application Deficiencies* - An analysis of calibration data may indicate a particular component that always tends to drift significantly more than all other similar components installed in the plant. In this case, the component may need an evaluation for the possibility of a design, application, or installation problem. Including this particular component in the same population as the other similar components may skew the drift analysis results.

3.6.1. Detection of Outliers

There are several methods for determining the presence of outliers. This design guide utilizes the Critical Values for t-Test (Extreme Studentized Deviate). The t-Test utilizes the values listed in Table 2 with an upper significance level of 5% to compare a given data point against. Note that the critical value of t increases as the sample size increases. This signifies that as the sample size grows, it is more likely that the sample is truly representative of the population. The t-Test assumes that the data is normally distributed.

Table 2 - Critical Values for t-Test

Sample Size	Upper 5% Significance Level	Sample Size	Upper 5% Significance Level
≤ 3	1.15	22	2.60
4	1.46	23	2.62
5	1.67	24	2.64
6	1.82	25	2.66
7	1.94	≤ 30	2.75
8	2.03	≤ 35	2.82
9	2.11	≤ 40	2.87
10	2.18	≤ 45	2.92
11	2.23	≤ 50	2.96
12	2.29	≤ 60	3.03
13	2.33	≤ 70	3.09
14	2.37	≤ 75	3.10
15	2.41	≤ 80	3.14
16	2.44	≤ 90	3.18
17	2.47	≤ 100	3.21
18	2.50	≤ 125	3.28
19	2.53	≤ 150	3.33
20	2.56	>150	4.00
21	2.58		

3.6.2. t-Test Outlier Detection Equation

$$t = \frac{|x_i - \bar{x}|}{s}$$ (Ref. 7.1.1)

Where;

X_i - An individual sample data point

$\overline{X}$ - Mean of all sample data points

s - Standard deviation of all sample data points

t - Calculated value of extreme studentized deviate that is compared to the critical value of t for the sample size.

3.6.3. Outlier Expulsion

This design guide does not permit multiple outlier tests or passes. The removal of poor quality data as listed in Section 3.6 is not considered removal of outliers, since it is merely assisting in identifying data errors. However, after removal of poor quality data as listed in Section 3.6, certain data points can still appear as outliers when the outlier analysis is performed. These "unique outliers" are not consistent with the other data collected; and could be judged as erroneous points, which tend to skew the representation of the distribution of the data. However, for the general case, since these outliers may accurately represent instrument performance, only one (1) additional unique outlier (as indicated by the t-Test), may be removed from the drift data. After removal of poor quality data and the removal of the unique outlier (if necessary), the remaining drift data is known as the Final Data Set.

For transmitters or other devices with multiple calibration points, the general process is to use the calibration point with the worst-case drift values. This is determined by comparing the different calibration points and using the one with the largest error, determined by adding the absolute value of the drift mean to 2 times the drift standard deviation. The data set with the largest of those terms is used throughout the rest of the analysis, after outlier removal, as the Final Data Set. (Note that it is possible to use a specific calibration point and neglect the others, only if that is the single point of concern for application of the results of the Drift Calculation. If so, this fact should be stated boldly in the results / conclusions of the calculation.)

The data set basic statistics (i.e., the Mean, Median, Standard Deviation, Variance, Minimum, Maximum, Kurtosis, Skewness, Count and Average Time Interval between Calibrations) should be computed and displayed for the data set prior to removal of the unique outlier and for the Final Data Set, if different.

3.7. Methods for Verifying Normality

A test for normality can be important because many frequently used statistical methods are based upon an assumption that the data is normally distributed. This assumption applies to the analysis of component calibration data also. For example, the following analyses may rely on an assumption that the data is normally distributed:

- Determination of a tolerance interval that bounds a stated proportion of the population based on calculation of mean and standard deviation
- Identification of outliers
- Pooling of data from different samples into a single population

The normal distribution occurs frequently and is an excellent approximation to describe many processes. Testing the assumption of normality is important to confirm that the data appears to fit the model of a normal distribution, but the tests do not prove that the normal distribution is a correct model for the data. At best, it can only be found that the data is reasonably consistent with the characteristics of a normal distribution, and that the treatment of a distribution as normal is conservative. For example, some tests for normality only allow the rejection of the hypothesis that the data is normally distributed. A group of data passing the test does not mean the data is normally distributed; it only means that there is no evidence to say that it is not normally distributed. However, because of the wealth of industry evidence that drift can be conservatively represented by a normal distribution, a group of data passing these tests is considered as normally distributed without adjustments to the standard deviation of the data set.

Distribution-free techniques are available when the data is not normally distributed; however, these techniques are not as well known and often result in penalizing the results by calculating tolerance intervals that are substantially larger than the normal distribution equivalent. Because of this fact, there is a good reason to demonstrate that the data is normally distributed or can be bounded by the assumption of normality.

Analytically verifying that a sample appears to be normally distributed usually invokes a form of statistics known as hypothesis testing. In general, a hypothesis test includes the following steps:

1) Statement of the hypothesis to be tested and any assumptions
2) Statement of a level of significance to use as the basis for acceptance or rejection of the hypothesis
3) Determination of a test statistic and a critical region
4) Calculation of the appropriate statistics to compare against the test statistic
5) Statement of conclusions

The following sections discuss various ways in which the assumption of normality can be verified to be consistent with the data or can be claimed to be a conservative representation of the actual data. Analytical hypothesis testing and subjective graphical analyses are discussed. If the analytical hypothesis test (either Chi-Squared or D Prime / W Test) are passed, the coverage analysis and additional graphical analyses are not required. Generally, only a single hypothesis test should be performed on a given data set. Because of the consistent approach given for the D Prime and W tests from Reference 7.1.4, these tests are recommended. However, use of the Chi-Squared test is allowed in place of the D Prime or W Test, if desired. The following are descriptions of the methods for assessing normality.

3.7.1. Chi-Squared, x^2, Goodness of Fit Test

This well-known test is stated as a method for assessing normality in References 7.1.1 and 7.1.2. The x^2 test compares the actual distribution of sample values to the expected distribution. The expected values are calculated by using the normal mean and standard deviation for the sample. If the distribution is normally or approximately normally distributed, the difference between the actual versus expected values should be very small. And, if the distribution is not normally distributed, the differences should be significant.

3.7.1.1. Equations to Perform the x^2 Test

1) First calculate the mean for the sample group

$$\overline{X} = \frac{\sum X_i}{n} \qquad \text{(Ref. 7.1.1)}$$

Where;

X_i - An individual sample data point

$\overline{X}$ - Mean of all sample data points

n - Total number of data points

2) Second calculate the standard deviation for the sample group

$$s = \sqrt{\frac{n\sum x^2 - \left(\sum x\right)^2}{n(n-1)}} \qquad \text{(Ref. 7.1.1)}$$

Where;

x - Sample data values (x1, x2, x3, ...)

s - Standard deviation of all sample data points

n - Total number of data points

3) Third the data must be divided into bins to aid in determination of a normal distribution. The number of bins selected is up to the individual performing the analysis. Refer to Reference 7.1.1 for further guidance. For most applications, a 12-bin analysis is performed on the drift data. See Section 4.4.

4) Fourth calculate the x^2 value for the sample group

$$x^2 = \sum \frac{(O_i - E_i)^2}{E_i} \qquad E_i = NP_i \qquad \text{(Ref. 7.1.1)}$$

Where;

E_i - Expected values for the sample

N - Total number of samples in the population

P_i - Probability that a given sample is contained in a bin

O_i - Observed sample values (O_1, O_2, O_3, ...)

x^2 - Chi squared result

5) Fifth, calculate the degrees of freedom. The degrees of freedom term is computed as the number of bins used for the chi-square computation minus the constraints. In all cases for these Drift Calculations, since the count, mean and standard deviation are computed, the constraints term is equal to three.

6) Sixth, compute the Chi squared per degree of freedom term (X_0^2). This term is merely the Chi squared term computed in step 4 above, divided by the degrees of freedom.

7) Finally, evaluate the results. The results are evaluated in the following manner, as prescribed in Reference 7.1.1. If the Chi squared result computed in step 4 is less than or equal to the degrees of freedom, the assumption that the distribution is normal is not rejected. If the value from step 4 is greater than the degrees of freedom, then one final check is made. The degrees of freedom and X_0^2 are used to look up the probability of obtaining a X_0^2 term greater than the observed value, in percent. (See Table C-3 of Reference 7.1.1.) If the lookup value is greater than or equal to 5%, then the assumption of normality is not rejected. However, if the lookup value is less than 5%, the assumption of normality is rejected.

3.7.2. W Test

Reference 7.1.4 recommends this test for sample sizes less than 50. The W Test calculates a test statistic value for the sample population and compares the calculated value to the critical values for W, which are tabulated in Reference 7.1.4. The W Test is a lower-tailed test. Thus if the calculated value of W is less than the critical value of W, the assumption of normality would be rejected at the stated significance level. If the calculated value of W is larger than the critical value of W, there is no evidence to reject the assumption of normality. Reference 7.1.4 establishes the methods and equations required for performing a W Test.

3.7.3. D-Prime Test

Reference 7.1.4 recommends this test for moderate to large sample sizes, greater than or equal to 50. The D′ Test calculates a test statistic value for the sample population and compares the calculated value to the values for the D′ percentage points of the distribution, which are tabulated in Reference 7.1.4. The D′ Test is two-sided, which means that the two-sided percentage limits at the stated level of significance must envelop the calculated D′ value. For the given sample size, the calculated value of D′ must lie within the two values provided in the Reference 7.1.4 table in order to accept the hypothesis of normality.

3.7.3.1. Equations to Perform the D′ Test

1) First, calculate the linear combination of the sample group. (Note: Data must be placed in ascending order of magnitude, prior to the application of this formula.)

$$T = \Sigma\left[\left(i - \frac{n+1}{2}\right) \times x_i\right]$$ (Ref. 7.1.4)

Where;

T - Linear combination

x_i - An individual sample data point

i - The number of the sample point

n - Total number of data points

2) Second, calculate the S^2 for the sample group.

$$S^2 = (n-1)s^2$$ (Ref. 7.1.4)

Where;

S^2 - Sum of the Squares about the mean

s^2 - Unbiased estimate of the sample population variance

n - Total number of data points

3) Third, calculate the D′ value for the sample group.

$$D' = \frac{T}{S}$$ (Ref. 7.1.4)

4) Finally, evaluate the results. If the D' value lies within the acceptable range of results (for the given data count) per Table 5 of Reference 7.1.4, for the P = 0.025 and 0.975, then the assumption of normality is not rejected. (If the exact data count is not contained within the tables, the critical value limits for the D' value should be linearly interpolated to the correct data count.) If however, the value lies outside that range, the assumption of normality is rejected.

3.7.4. Probability Plots

For most Drift Calculations performed per this methodology, probability plots will not be included, since numerical methods or coverage analyses are recommended. However, probability plots are discussed, since a graphical presentation of the data can sometimes reveal possible reasons for why the data is or is not normal. A probability plot is a graph of the sample data with the axes scaled for a normal distribution. If the data is normal, the data tends to follow a straight line. If the data is non-normal, a nonlinear shape should be evident from the graph. This method of normality determination is subjective, and is not required if the numerical method shows the data to be normal, or if a coverage analysis is used. The types of probability plots used by this design guide are as follows:

- *Cumulative Probability Plot* - an XY scatter plot of the Final Data Set plotted against the percent probability (P_i) for a normal distribution. P_i is calculated using the following equation:

$$P_i = \frac{100 \times \left(i - \frac{1}{2}\right)}{n} \qquad \text{(Ref. 7.1.1)}$$

where; i = sample number i.e. 1,2,...
n = sample size

NOTE: Refer, as necessary, to Appendix C Section C.4 of Reference 7.1.1.

- *Normalized Probability Plot* - an XY scatter plot of the Final Data Set plotted against the probability for a normal distribution, expressed in multiples of the standard deviation.

3.7.5. Coverage Analysis

A coverage analysis is recommended for cases in which the hypothesis tests reject the assumption of normality, but the assumption of normality is still a conservative representation of the data. The coverage analysis involves the use of a histogram of the Final Data Set, overlaid with the equivalent probability distribution curve for the normal distribution, based on the data sample's mean and standard deviation.

Visual examination of the plot is used to determine if the distribution of the data is near normal, or if a normal distribution model for the data would adequately cover the data within the 2 sigma limits. Another measure of the conservatism in the use of a normal distribution as a model is the kurtosis of the data. Reference 7.1.1 states that samples that have a large value of kurtosis are the most likely candidates for a coverage analysis. Kurtosis characterizes the relative peakedness or flatness of the distribution compared to the normal distribution, and is readily calculated within statistical and spreadsheet programs. As shown in Reference 7.1.1, a positive kurtosis indicates a relatively high peaked distribution, and a negative kurtosis indicates a relatively flat distribution, with respect to the normal distribution.

If the data is near normal or is more peaked than a normal distribution (positive kurtosis), then a normal distribution model is derived, which adequately covers the set of drift data, as observed. This normal distribution is used as the model for the drift of the device. Sample counting is used to determine an acceptable normal distribution model. The Standard Deviation of the group is computed. The number of samples that are within ± two Standard Deviations of the mean is computed. The count is divided by the total number of samples in the group to determine a percentage. The following table provides the percentage that should fall within the two Standard Deviation values for a normal distribution.

Table 3 – Population Percentage for a Normal Distribution

	Percentage for a Normal Distribution
2 Standard Deviations	95.45%

If the percentage of data within the two standard deviations tolerance is greater than the value in Table 3 for a given data set, the existing standard deviation is acceptable to be used for the encompassing normal distribution model. However, if the percentage is less than required, the standard deviation of the model is enlarged, such that greater than or equal to the required percentage falls within the ± two Standard Deviations bounds. The required multiplier for the standard deviation in order to provide this coverage is termed the Normality Adjustment Factor (NAF). If no adjustment is required, the NAF is equal to one (1).

3.8. Time-Dependent Drift Analysis

The component/loop drift calculated in the previous sections represented a predicted performance limit, without any consideration of whether the drift may vary with time between calibrations or component age. This section discusses the importance of understanding the time-related performance and the impact of any time-dependency on an analysis. Understanding the time dependency can be either important or unimportant, depending on the application. A time dependency analysis is important whenever the drift analysis results are intended to support an extension of calibration intervals.

3.8.1. Limitations of Time Dependency Analyses

Reference 7.1.1 performed drift analysis for numerous components at several nuclear plants as part of the project. The data evaluated did not demonstrate any significant time-dependent or age-dependent trends. Time dependency may have existed in all of the cases analyzed, but was insignificant in comparison to other uncertainty contributors. Because time dependency cannot be completely ruled out, there should be an ongoing evaluation to verify that component drift continues to meet expectations whenever calibration intervals are extended.

3.8.2. Scatter (Drift Interval) Plot

A drift interval plot is an XY scatter plot that shows the Final Data Set plotted against the time interval between tests for the data points. This plot method relies upon the human eye to discriminate the plot for any trend in the data to exhibit time dependency. A prediction line can be added to this plot which shows a "least squares" fit of the data over time. This can provide visual evidence of an increasing or decreasing mean over time, considering all drift data. An increasing standard deviation is indicated by a trend towards increasing "scatter" over the increased calibration intervals.

3.8.3. Standard Deviations and Means at Different Calibration Intervals (Binning Analysis)

This analysis technique is the most recommended method of determining time dependent tendencies in a given sample pool. (See Reference 7.1.1.) The test consists simply of segregating the drift data into different groups (Bins) corresponding to different ranges of calibration or surveillance intervals and comparing the standard deviations and means for the data in the various groups. The purpose of this type of analysis is to determine if the standard deviation or mean tends to become larger as the time interval between calibrations increases.

3.8.3.1. The available data is placed in interval bins. The intervals normally used at RBS or GGNS coincide with Technical Specification calibration intervals plus the allowed tolerance as follows:

a. 0 to 45 days (covers most weekly and monthly calibrations)

b. 46 to 135 days (covers most quarterly calibrations)

c. 136 to 230 days (covers most semi-annual calibrations)

d. 231 to 460 days (covers most annual calibrations)

e. 461 to 690 days (covers most 18 month refuel cycle calibrations)

f. 691 to 915 days (covers most extended refuel cycle calibrations)

g. > 915 days covers missed and forced outage refueling cycle calibrations.

Data will naturally fall into these time interval bins based on the calibration requirements for the subject instrument loops. Only on occasion will a device be calibrated on a much longer or shorter interval than that of the rest of the population within its calibration requirement group. Therefore, the data will naturally separate into groups for analysis.

3.8.3.2. Although not generally recommended, different bin splits could be used, but must be evaluated for data coverage, significant diversity in calibration intervals, and acceptable data groupings.

3.8.3.3. For each bin where there is data, the mean (average), standard deviation, average time interval and data count will be computed.

3.8.3.4. To determine if time dependency does or does not exist, the data must be distributed across multiple bins, with a sufficient population of data in each of two or more bins, to consider the statistical results for those bins to be valid. Normally the minimum expected distribution that would allow evaluation is defined below.

a. A bin is considered valid in the final analysis if it holds more than five data points and more than ten percent of the total data count.
b. At least two bins, including the bin with the most data, must be left for evaluation to occur.

The distribution percentages listed in these criteria are somewhat arbitrary, and thus engineering evaluation can modify them for a given situation.

The mean and standard deviations of the valid bins are plotted versus average time interval on a diagram. This diagram can give a good visual indication of whether or not the mean or standard deviation of a data set is increasing significantly over time interval between calibrations.

If the binning analysis plot shows an increase in standard deviation over time, the critical value of the F-distribution is compared to the ratio of the smallest and largest variances for the evaluated bins. If the ratio of variances exceeds the critical value, this result is indicative of time dependency for the random portion of drift. Likewise, a ratio of variances not exceeding the critical value is not indicative of significant time dependency.

NOTE: If multiple valid bins do NOT exist for a given data set, then the plot is not to be shown, and the regression analyses are not to be performed. The reasoning is that there is not enough diversity in the calibration intervals analyzed to make meaningful conclusions about time dependency from the existing data. Unless overwhelming evidence to the contrary exists in the scatter plot, the single bin data set is treated as moderately time dependent for the purposes of extrapolation of the drift value.

3.8.4. Regression Analyses and Plots

Regression Analyses can often provide very valuable data for the determination of time dependency. A standard regression analysis within an EXCEL spreadsheet can plot the drift data versus time, with a prediction line showing the trend. It can also provide Analysis of Variance (ANOVA) table printouts, which contain information required for various numerical tests to determine level of dependency between two parameters (time and drift value). Note that regression analyses are only to be performed if multiple valid bins are determined from the binning analysis.

Regression Analyses are to be performed on the Final Data Set drift values and on the Absolute Value of the Final Data Set drift values. The Final Data Set drift values show trends for the mean of drift, and the Absolute Values show trends for the standard deviation over time.

<u>*Regression Plots*</u>

The following are descriptions of the two plots generated by these regressions.

- *Drift Regression* - an XY scatter plot that fits a line through the final drift data, plotted against the time interval between tests for the data points, using the "least squares" method to predict values for the given data set. The predicted line is plotted through the actual data for use in predicting drift over time. It is important to note that statistical outliers can have a dramatic effect upon the regression line.
- *Absolute Value Drift Regression* - an XY scatter plot that fits a line through the Absolute Value of the final drift data, plotted against the time interval between tests for the data points, using the "least squares" method to predict values for the given data set. The predicted line is plotted through the actual data for use in predicting drift, in either direction, over time. It is important to note that statistical outliers can have a dramatic effect upon the regression line.

<u>*Regression Time Dependency Analytical Tests*</u>

Typical spreadsheet software includes capabilities to include ANOVA tables with regression analyses. ANOVA tables give various statistical data, which can allow certain numerical tests to be employed, to search for time dependency. For each of the two regressions (drift regression and absolute value drift regression), the following ANOVA parameters are used to determine if time dependency of the drift data is evident. All tests listed should be evaluated, and if time dependency is indicated by any of the tests, the data should be considered as time dependent.

- *R Squared Test* - The R Squared value, printed out in the ANOVA table, is a relatively good indicator of time dependency. If the value is greater than 0.09 (thereby indicating the R value greater than 0.3), then it appears that the data closely conforms to a linear function, and therefore, should be considered time dependent.
- *P Value Test* - A P Value for X Variable 1 (as indicated by the ANOVA table for an EXCEL spreadsheet) less than 0.05 is indicative of time dependency.
- *Significance of F Test* - An ANOVA table F value greater than the critical F-table value would indicate a time dependency. In an EXCEL spreadsheet, the FINV function can be used to return critical values from the F distribution. To return the critical value of F, use the significance level (in this case 0.05 or 5.0%) as the probability argument to FINV, 2 as the numerator degrees of freedom, and the data count minus two as the denominator. If the F value in the ANOVA table exceeds the critical value of F, then the drift is considered time dependent.

NOTE: For each of these tests, if time dependency is indicated, the plots should be observed to determine the reasonableness of the result. The tests above generally assess the possibility that the function of drift is linear over time, not necessarily that the function is significantly increasing over time. Time dependency can be indicated even when the plot shows the drift to remain approximately the same or decrease over time. Generally, a decreasing drift over time is not expected for instrumentation, nor is a case where the drift function crosses zero. Under these conditions, the extrapolation of the drift term would normally be established assuming no time dependency, if extrapolation of the results is required beyond the analyzed time intervals between calibrations.

3.8.5. Additional Time Dependency Analyses

- *Instrument Resetting Evaluation* - For data sets that consist of a single calibration interval the time dependency determination may be accomplished simply by evaluating the frequency at which instruments require resetting. This type of analysis is particularly useful when applied to extend quarterly Technical Specification surveillances to semi-annual. However, this type of analysis is less useful for instruments such as sensors or relays that may be reset at each calibration interval, regardless of whether the instrument was already in calibration.

  The Instrument Resetting Evaluation may be performed only if the devices in the sample pool are shown to be stable, not requiring adjustment (i.e. less than 5% of the data shows that adjustments were made). Care also must be taken when mechanical connections or flex points may be exercised by the act of checking calibration (actuation of a bellows or switch movement), where the act of checking the actuation point may have an effect on the next reading. Methodology for calculating the drift is as follows:

  Quarterly As-Found/As-Left

  (As-Found Current Calibration - As-Left Previous Calibration) or $AF_1 - AL_2$ (Ref. 7.1.1)

  Semi-Annual As-Found/As-Left using Monthly Data

  $(AF_1 - AL_2) + (AF_2 - AL_3)$ (Ref. 7.1.1)

3.8.6. Age-Dependent Drift Considerations

Age-dependency is the tendency for a component's drift to increase in magnitude as the component ages. This can be assessed by plotting the As-Found value for each calibration minus the previous calibration As-Left value of each component over the period of time for which data is available. Random fluctuations around zero may obscure any age-dependent drift trends. By plotting the absolute values of the As-Found versus As-Left calibration data, the tendency for the magnitude of drift to increase with time can be assessed. This analysis is generally not performed as a part of a standard Drift Calculation, but can be used, if desired, when establishing maintenance practices.

3.9. Calibration Point Drift

For devices with multiple calibration points (e.g., transmitters, indicators, etc.) the Drift-Calibration Point Plot is a useful tool for comparing the amount of drift exhibited by the group of devices at the different calibration points. The plot consists of a line graph of tolerance interval as a function of calibration point. This is useful to understand the operation of an instrument, but is not normally included as a part of a standard Drift Calculation.

3.10. Drift Bias Determination

If an instrument or group of instruments consistently drifts predominately in one direction, the drift is assumed to have a bias. When the absolute value of the calculated average for the sample pool exceeds the values in Table 4 for the given sample size and calculated standard deviation, the average is treated as a bias to the drift term. The application of the bias must be carefully considered separately, so that the overall treatment of the analyzed drift remains conservative. The values for x_{crit} may be used directly from Table 4 or may be calculated, using the equation below the table. Refer to Example 1 below.

Table 4 – Maximum Values of Non-Biased Mean

Sample Size (n)	Normal Deviate (t) @ 0.025 for 95% Confidence	Maximum Value of Non-Biased Mean (x_{crit}) For Given STDEV (s)								
		s ≥ 0.10%	s ≥ 0.25%	s ≥ 0.50%	s ≥ 0.75%	s ≥ 1.00%	s ≥ 1.50%	s ≥ 2.00%	s ≥ 2.50%	s ≥ 3.00%
≤5	2.571	0.115	0.287	0.575	0.862	1.150	1.725	2.300	2.874	3.449
≤10	2.228	0.070	0.176	0.352	0.528	0.705	1.057	1.409	1.761	2.114
≤15	2.131	0.055	0.138	0.275	0.413	0.550	0.825	1.100	1.376	1.651
≤20	2.086	0.047	0.117	0.233	0.350	0.466	0.700	0.933	1.166	1.399
≤25	2.060	0.041	0.103	0.206	0.309	0.412	0.618	0.824	1.030	1.236
≤30	2.042	0.037	0.093	0.186	0.280	0.373	0.559	0.746	0.932	1.118
≤40	2.021	0.032	0.080	0.160	0.240	0.320	0.479	0.639	0.799	0.959
≤60	2.000	0.026	0.065	0.129	0.194	0.258	0.387	0.516	0.645	0.775
≤120	1.980	0.018	0.045	0.090	0.136	0.181	0.271	0.361	0.452	0.542
>120	1.960	(Values Above are Computed per Equation Below)								

The maximum values of non-biased mean (x_{crit}) for a given standard deviation (s) and sample size (n) is calculated using the following formula:

$$x_{crit} = t \times \frac{s}{\sqrt{n}}$$ (Ref. 7.3.2)

Where;

X_{crit} = Maximum value of non-biased mean for a given s & n, expressed in %
t = Normal Deviate for a t-distribution @ 0.025 for 95% Confidence
s = Standard Deviation of sample pool
n = Sample pool size

Examples of determining and applying bias to the analyzed drift term:

1) <u>Transmitter Group With a Biased Mean</u> - A group of transmitters are calculated to have a standard deviation of 1.150%, mean of - 0.355% with a count of 47. From Table 4, the maximum value that a negligible mean could be is ± 0.258%. Therefore, the mean value is significant, and must be considered. The analyzed drift term for a 95%/95% tolerance interval level is shown as follows.

   DA = - 0.355% ± 1.150% x 2.408 (TIF from Table 1 for 47 samples)
   DA = - 0.355% ± 2.769%

   For conservatism, the DA term for the positive direction is not reduced by the bias value where as the negative direction is summed with the bias value.

   DA = + 2.769%, - 3.124%.

2) Transmitter Group With a Non-Biased Mean - A group of transmitters are calculated to have a standard deviation of 1.150%, mean of 0.100% with a count of 47. From Table 4, the maximum value that a negligible mean could be is ± 0.258%. Therefore, the mean value is insignificant, and can be neglected. The analyzed drift term for a 95%/95% tolerance interval level is shown as follows.

   DA = ± 1.150% x 2.408 (TIF from Table 1 for 47 samples)
   DA = ± 2.769%

3.11. Time Dependent Drift Uncertainty

When calibration intervals are extended beyond the range for which historical data is available, the statistical confidence in the ability to predict drift is reduced. The bias and the random portions of the drift are extrapolated separately, but in the same manner. Where the analysis shows slight to moderate time dependency or time dependency is indeterminate, drift is extrapolated using the Square Root of the Sum of the Squares (SRSS) method per Section 6.2.7 of Reference 7.1.2. The formula below is used.

$$DA_{Extended} = DA \times \sqrt{\frac{Rqd\_Calibration\_Interval}{Max\_FDS\_Time\_Interval}}$$

Where: $DA_{Extended}$ = the newly determined, extrapolated Drift Bias or Random Term

DA = the bias or random drift term from the Final Data Set

Max_FDS_Time_Interval = the maximum observed time interval within the Final Data Set

Rqd_Calibration_Interval = the worst case calibration interval, once the calibration interval requirement is changed

This method assumes that the drift to time relationship is not linear. Where there is indication of a strong relationship between drift and time, drift is extrapolated using the linear method per Section 6.2.7 of Reference 7.1.2. the following formula may be used.

$$DA_{Extended} = DA \times \left[\frac{Rqd\_Calibration\_Interval}{Max\_FDS\_Time\_Interval}\right]$$

Where the terms are the same as defined above.

Where it can be shown that there is no relationship between surveillance interval and drift, the drift value determined may be used for other time intervals, without change. However, for conservatism, due to the uncertainty involved in extrapolation to time intervals outside of the analysis period, drift values that show minimal or no particular time dependency are generally treated as moderately time dependent, for the purposes of the extrapolation.

3.12. Shelf Life of Analysis Results

Any analysis result based on performance of existing components has a shelf life. In this case, the term "shelf life" is used to describe a period of time extending from the present into the future during which the analysis results are considered valid. Predictions for future component/loop performance are based upon our knowledge of past calibration performance. This approach assumes that changes in component/loop performance occur slowly or not at all over time. For example, if evaluation of the last ten years of data shows the component/loop drift is stable with no observable trend, there is little reason to expect a dramatic change in performance during the next year. However, it is also difficult to claim that an analysis completed today is still a valid indicator of component/loop performance ten years from now. For this reason, the analysis results should be re-verified periodically through an instrument trending program in accordance with Reference 7.1.1. The Analyzed Drift values from the Drift

Calculations are to be used by the trending program as thresholds, which will require further investigation if exceeded.

Depending on the type of component/loop, the analysis results are also dependent on the method of calibration, the component/loop span, and the M&TE accuracy. Any of the following program or component/loop changes should be evaluated to determine if they affect the analysis results.

- Changes to M&TE accuracy
- Changes to the component or loop (e.g. span, environment, manufacturer, model, etc.)
- Calibration procedure changes that alter the calibration method

4. PERFORMING AN ANALYSIS

As Found and As Left calibration data for the subject instrumentation is collected from historical calibration records. The collected data is entered into Microsoft Excel spreadsheets, grouped by manufacturer and model number. All data is also entered into an independent software program (such as IPASS, Lotus 1-2-3, or SYSTAT), for independent review of certain of the drift analysis functions. The drift analysis is generally performed using EXCEL spreadsheets, but can be performed using other software packages. The discussion provided in this section is to assist in setting up an EXCEL spreadsheet for producing a Drift Calculation. For IPASS analysis instructions, see the IPASS User's Manual (Reference 7.3.1).

Microsoft Excel spreadsheets generally compute values to an approximate 15 decimal resolution, which is well beyond any required rounding for engineering analyses. However, for printing and display purposes, most values are displayed to lesser resolution. It is possible that hand computations would produce slightly different results, because of using rounded numbers in initial and intermediate steps, but the Excel computed values are considered highly accurate in comparison. Values with significant differences between the original computations and the computations of the independent verifier are to be investigated to ensure that the Excel spreadsheet is properly computing the required values.

4.1. Populating the Spreadsheet

4.1.1. For a New Analysis

4.1.1.1. The Responsible Engineer determines the component group to be analyzed (e.g., all Rosemount pressure transmitters). The Responsible Engineer should determine the possible sub-groups within the large groupings, which from an engineering perspective, might show different drift characteristics; and therefore, may warrant separation into smaller groups. This determination would involve the manufacturer, model, calibration span, setpoints, time intervals, specifications, locations, environment, etc., as necessary.

4.1.1.2. The Responsible Engineer develops a list of component numbers, manufacturers, models, component types, brief descriptions, surveillance tests, calibration procedures and calibration information (spans, setpoints, etc.).

4.1.1.3. The Responsible Engineer determines the data to be collected, following the guidance of Sections 3.4 through 3.6 of this Design Guide.

4.1.1.4. The Data Entry Person identifies, locates and collects data for the component group to be analyzed (e.g., all Surveillance Tests for the Rosemount pressure transmitters completed to present).

4.1.1.5. The Data Entry Person sorts the data by surveillance test or calibration procedure if more than one test/procedure is involved.

4.1.1.6. The Data Entry Person sequentially sorts the surveillance or calibration sheets descending, by date, starting with the most recent date.

4.1.1.7. The Data Entry Person enters the Surveillance or Calibration Procedure Number, Tag

Numbers, Required Trips, Indications or Outputs, Date, As-Found values and As-Left values on the appropriate data entry sheet.

4.1.1.8. The Responsible Engineer verifies the data entered.

4.1.1.9. The Responsible Engineer reviews the notes on each calibration data sheet to determine possible contributors for excluding data. The notes should be condensed and entered onto the EXCEL spreadsheet for the applicable calibration points. Where appropriate and obvious, the Responsible Engineer should remove the data that is invalid for calculating drift for the device.

4.1.1.10. The Responsible Engineer (via the spreadsheet) calculates the time interval for each drift point by subtracting the date from the previous calibration from the date of the subject calibration. (If the measured value is not valid for the As-Left or As-Found calibration information, then the time interval is not required to be computed for this data point.)

4.1.1.11. The Responsible Engineer (via the spreadsheet) calculates the Drift value for each calibration by subtracting the As-Left value from the previous calibration from the As-Found value of the subject calibration. (If the measured value is not valid for the As-Left or As-Found calibration information, then the Drift value is not computed for this data point.)

4.2. Spreadsheet Performance of Basic Statistics

Separate data columns are created for each calibration point within the calibrated span of the device. The % Span of each calibration point should closely match from device to device within a given analysis. Basic statistics include, at a minimum, determining the number of data points in the sample, the average drift, the average time interval between calibrations, standard deviation of the drift, variance of the drift, minimum drift value, maximum drift value, kurtosis, and skewness contained in each data column. This section provides the specific details for using Microsoft Excel. Other spreadsheet, statistical or Math programs that are similar in function, are acceptable for use to perform the data analysis, provided all analysis requirements are met.

4.2.1. Determine the number of data points contained in each column for each initial group by using the "COUNT" function. Example cell format = **COUNT(C2:C133)**. The Count function returns the number of all populated cells within the range of cells C2 through C133.

4.2.2. Determine the average for the data points contained in each column for each initial group by using the "AVERAGE" function. Example cell format = **AVERAGE(C2:C133)**. The Average function returns the average of the data contained within the range of cells C2 through C133. This average is also known as the mean of the data. This same method should be used to determine the average time interval between calibrations.

4.2.3. Determine the standard deviation for the data points contained in each column for each initial group by using the "STDEV" function. Example cell format =**STDEV(C2:C133)**. The Standard Deviation function returns the measure of how widely values are dispersed from the mean of the data contained within the range of cells C2 through C133. Formula used by Microsoft Excel to determine the standard deviation:

STD (Standard Deviation of the sample population): (Ref. 7.3.4)

$$s = \sqrt{\frac{n\sum x^2 - \left(\sum x\right)^2}{n(n-1)}}$$

Where;

x - Sample data values (x_1, x_2, x_3, ...)

s - Standard deviation of all sample data points
n - Total number of data points

4.2.4. Determine the variance for the data points contained in each column for each initial group by using the "VAR" function. Example cell format **=VAR(C2:C133)**. The Variance function returns the measure of how widely values are dispersed from the mean of the data contained within the range of cells C2 through C133. Formula used by Microsoft Excel to determine the variance:

VAR (Variance of the sample population): (Ref. 7.3.4)

$$s^2 = \frac{n\sum x^2 - \left(\sum x\right)^2}{n(n-1)}$$

Where;

x - Sample data values (x_1, x_2, x_3, ...)
s^2 - Variance of the sample population
n - Total number of data points

4.2.5. Determine the kurtosis for the data points contained in each column for each initial group by using the "KURT" function. Example cell format **=KURT(C2:C133)**. The Kurtosis function returns the relative peakedness or flatness of the distribution within the range of cells C2 through C133. Formula used by Microsoft Excel to determine the kurtosis:

$$KURT = \left\{ \frac{n(n+1)}{(n-1)(n-2)(n-3)} \sum \left(\frac{x_i - \bar{x}}{s} \right)^4 \right\} - \frac{3(n-1)^2}{(n-2)(n-3)}$$ (Ref. 7.3.4)

Where ;

x - Sample data values (x_1, x_2, x_3, ...)
n - Total number of data points
s - Sample Standard Deviation

4.2.6. Determine the skewness for the data points contained in each column for each initial group by using the "SKEW" function. Example cell format **=SKEW(C2:C133)**. The Skewness function returns the degree of symmetry around the mean of the cells contained within the range of cells C2 through C133. Formula used by Microsoft Excel to determine the skewness:

$$SKEW = \frac{n(n+1)}{(n-1)(n-2)} \sum \left(\frac{x_i - \bar{x}}{s} \right)^3$$ (Ref. 7.3.4)

Where;

x - Sample data values (x_1, x_2, x_3, ...)
n - Total number of data points
s - Sample Standard Deviation

4.2.7. Determine the maximum value for the data points contained in each column for each initial group by using the "MAX" function. Example cell format **=MAX(C2:C133)**. The Maximum function returns the largest value of the cells contained within the range of cells C2 through C133.

4.2.8. Determine the minimum value for the data points contained in each column for each initial group by using the "MIN" function. Example cell format =**MIN(C2:C133)**. The Minimum function returns the smallest value of the cells contained within the range of cells C2 through C133.

4.2.9. Determine the median value for the data points contained in each column for each initial group by using the "MEDIAN" function. Example cell format =**MEDIAN(C2:C133)**. The median is the number in the middle of a set of numbers; that is, half the numbers have values that are greater than the median, and half have values that are less. If there is an even number of data points in the set, then MEDIAN calculates the average of the two numbers in the middle.

4.2.10. Where sub-groups have been combined in a data set, and where engineering reasons exist for the possibility that the data should be separated, analyze the statistics and component data of the sub-groups to determine the acceptability for combination..

4.2.11. Perform a t-Test in accordance with step 3.5.4 on each possible sub-group combination to test for the acceptability of combining the data.

Acceptability for combining the data is indicated when the absolute value of the Test Statistic [t Stat] is greater than the [t Critical two-tail]. Example: t Stat for combining sub-group A & B may be 0.703, which is larger than the t Critical two-tail of 0.485. However, as a part of this process, the Responsible Engineer should ensure that the apparent unacceptability for combination does not mask time dependency. In other words, if the only difference in the groupings is that of the calibration interval, the differences in the data characteristics could exist because of time dependent drift. If this is the only difference, the data should be combined, even though the tests show that it may not be appropriate.

4.3. Outlier Detection and Expulsion

Refer to Section 3.6 for a detailed explanation of Outliers.

4.3.1. Obtain the Critical Values for the t-Test from Table 2, which is based on the sample size of the data contained within the specified range of cells. Use the COUNT value to determine the sample size.

4.3.2. Perform the outlier test for all the samples. For any values that show up as outliers, analyze the initial input data to determine if the data is erroneous. If so, remove the data in the earlier pages of the spreadsheet, and re-run all of the analysis up to this point. Continue this process until all erroneous data has been removed.

4.3.3. If appropriate, if any outliers are still displayed, remove the worst-case outlier as a statistical outlier, per step 3.6.3. Once this outlier has been removed (if applicable), the remaining data set is the Final Data Set.

4.3.4. For transmitters, or other devices with multiple calibration points, the general process is to use the calibration point with the worst case drift values. This is determined by comparing the different calibration points and using the one with the largest error, determined by adding the absolute value of the mean to 2 times the standard deviation. The data set with the largest of those terms is used throughout the rest of the analysis, after outlier removal, as the Final Data Set. (Note that it is possible to use a specific calibration point and neglect the others, <u>only</u> if that is the single point of concern for application of the results of the Drift Calculation. If so, this fact should be stated boldly in the results / conclusions of the calculation.)

4.3.5. Recalculate the Average, Median, Standard Deviation, Variance, Minimum, Maximum, Kurtosis, Skewness, Count and Average Time Interval Between Calibrations for the Final Data Set.

4.4. Normality Tests

To test for normality of the Final Data Set, the first step is to perform the required hypothesis testing. For Final Data Sets with 50 or more data points, the hypothesis testing can be performed with either the Chi-Square (Section 3.7.1) or the D-Prime Test (Section 3.7.3). The D-Prime Test is recommended. If the Final Data Set has less than 50 data points, the W Test (Section 3.7.2) or Chi-Square Test may be used. The W Test is recommended.

If used, the Chi Square test should generally be performed with 12 bins of data, starting from [$-\infty$ to (mean-2.5σ)], and bin increments of 0.5σ, ending at [(mean+2.5σ) to $+\infty$]. (Since the same bins are to be used for the histogram in the coverage analysis, the work for these two tasks may be combined.)

If the assumption of normality is rejected by the numerical test, then a coverage analysis should generally be performed as described in Section 3.7.5. As explained above the for Chi Square test, the coverage analysis and histogram are established with a 12 bin approach unless inappropriate for the application.

If an adjustment is required to the standard deviation to provide a normal distribution that adequately covers the data set, then the required multiplier to the standard deviation (Normality Adjustment Factor (NAF)) is determined iteratively in the coverage analysis. This multiplier produces a normal distribution model for the drift, which shows adequate data population from the Final Data Set within the $\pm 2\sigma$ bounds of the model.

4.5. Time Dependency Testing

Time dependency testing is only required for instruments for which the calibration intervals are being extended; however, the scatter plot is recommended for information in all Drift Calculations. Time dependency is evaluated through the use of a scatter (drift interval) plot, binning analysis, and regression analyses. The methods for each of these are detailed below.

4.5.1. Scatter Plot

The scatter plot is performed under a new page to the spreadsheet entitled "Scatter Plot" or "Drift Interval Plot". The chart function of EXCEL is used to merely chart the data with the x axis being the calibration interval and the y axis being the drift value for the Final Data Set. The prediction line should be added to the chart, along with the equation of the prediction line. This plot provides visual indication of the trend of the mean, and somewhat obscurely, of any increases in the scatter of the data over time. Note: The trend line should NOT be forced to have a y-intercept value of 0, but should be plotted for the actual drift data only.

4.5.2. Binning Analysis

The binning analysis is performed under a separate page of the EXCEL spreadsheet. The Final Data Set is split by bins 1 through 8 into the time intervals as defined in Section 3.8.3.1. A table is set up to compute the standard deviation, mean, average time interval, and count of the data in each time bin. Similar equation methods are used here as described in Section 4.2, when characterizing the drift data set. Another table is used to evaluate the validity of the bins, based on population per the criteria of Section 3.8.3.4. If multiple valid bins are not established, the time dependency analysis stops here, and no regression analyses are performed.

If multiple valid bins are established, the standard deviations, means and average time intervals are tabulated, and a plot is generated to show the variation of the bin averages and standard deviations versus average time interval. This plot can be used to determine whether standard deviations and means are significantly increasing over time between calibrations.

If the plot shows an increase in standard deviation over time, compare the critical value of the F−distribution of the ratio of the smallest and largest variances for the required bins.

$$F_{calc} = \frac{s_1^{\ 2}}{s_2^{\ 2}}$$

where:

S_1 = largest drift standard deviation value

S_2 = smallest drift standard deviation value

The critical value of F-distribution can be found, using the FINV function in Microsoft Excel:

F_{crit} = FINV (0.05, V_1, V_2)

V_1 = number of samples minus 1 in bin with largest standard deviation

V_2 = number of samples minus 1 in bin with smallest standard deviation

If the ratio of variances exceeds the critical value, this result is indicative of time dependency for the random portion of drift. Likewise, a ratio of variances not exceeding the critical value is not indicative of significant time dependency.

4.5.3. Regression Analyses

The regression analyses are performed in accordance with the requirements of Section 3.8.4, given that multiple valid time bins were established in the binning analysis. New pages should be created for the Drift Regression and the Absolute Value Drift Regression.

For each of the two Regression Analyses, use the following steps to produce the regression analysis output. Using the "Data Analysis" package under "Tools" in Microsoft EXCEL, the Regression option should be chosen. The Y range is established as the Drift (or Absolute Value of Drift) data range, and the X range should be the calibration time intervals. The output range should be established on the Regression Analysis page of the spreadsheet. The option for the residuals should be established as "Line Fit Plots". The regression computation should then be performed. The output of the regression routine is a list of residuals, an ANOVA table listing, and a plot of the Drift (or Absolute Value of Drift) versus the Time Interval between Calibrations. A prediction line is included on the plot.

Add a cell close to the ANOVA table listing which establishes the Critical Value of F, using the guidance of Section 3.8.4 for the Significance of F Test. This utilizes the FINV function of Microsoft EXCEL.

Analyze the results in the Drift Regression ANOVA table for R Square, P Value, and F Value, using the guidance of Section 3.8.4. If any of these analytical methods shows time dependency in the Drift Regression, the mean of the data set should be established as strongly time dependent if the slope of the prediction line significantly increases over time from an initially positive value (or decreases over time from an initially negative value), without crossing zero within the time interval of the regression analysis. This increase can also be validated by observing the results of the binning analysis plot for the mean of the bins and by observing the scatter plot and regression analysis prediction lines.

Analyze the results in the Absolute Value of Drift Regression ANOVA table for R Square, P Value, and F Value, using the guidance of Section 3.8.4. If any of these analytical means shows time dependency, the standard deviation of the data set should be established as strongly time dependent if the slope of the prediction line significantly increases over time. This increase can also be validated by observing the results of the binning analysis plot for the standard deviation of the bins, by observation of the results from the F distribution comparison within the binning plot, and by observing any discernible increases in data scatter, as time increases, on the scatter plot.

Regardless of the results of the analytical regression tests, if the plots tend to indicate significant increases in either the mean or standard deviation over time, those parameters should be judged to be strongly time dependent. Otherwise, for conservatism, the data is always considered to be moderately time dependent if extrapolation of the data is necessary, to accommodate the uncertainty involved in the extrapolation process, since no data has generally been observed at time intervals as large as those proposed.

4.6. Calculate the Analyzed Drift (DA) Value

The first step in determining the Analyzed Drift Value is to determine the required time interval for which the value must be computed. For the majority of the cases for instruments calibrated on a refueling basis, the required nominal calibration time interval is 24 months, or a maximum of 30 months. Since the average time intervals are generally computed in days, the most conservative value for a 30-Month calibration interval is established as 915 days.

The Analyzed Drift Value generally consists of two separate components - a random term and a bias term. If the mean of the Final Data Set is significant per the criteria in Section 3.10, a bias term is considered. If no extrapolation is necessary, the bias term is set equal to the mean of the Final Data Set. If extrapolation is necessary, it is performed in one of two methods, as determined by the degree of time dependency established in the time dependency analysis. If the mean is determined to be strongly time dependent, the following equation is used, which extrapolates the value in a linear fashion.

$$DA_{Extended.bias} = \bar{x} \times \frac{Max\_Rqd\_Time\_Interval}{Max\_FDS\_Time\_Interval}$$

If the mean is determined to be moderately time dependent, the following equation is used to extrapolate the mean. (Note that this equation is also generally used for cases where no time dependency is evident, because of the uncertainty in defining a drift value beyond analysis limits.)

$$DA_{Extended.bias} = \bar{x} \times \sqrt{\frac{Max\_Rqd\_Time\_Interval}{Max\_FDS\_Time\_Interval}}$$

Where: $\bar{x}$ = Mean of the Final Data Set

Max_FDS_Time_Interval = the maximum observed time interval within the Final Data Set

Max_Rqd_Time_Interval = the maximum time interval for desired calibration interval. For instance, 915 days for a desired 24 month nominal calibration interval.

The random portion of the Analyzed Drift is calculated by multiplying the standard deviation of the Final Data Set by the Tolerance Interval Factor for the sample size and by the Normality Adjustment Factor (if required from the Coverage Analysis). If extrapolation is necessary, it is performed in one of two methods, similar to the methods shown above for the bias term, depending on the degree of time dependency observed. Use the following procedure to perform the operation.

4.6.1. Use the COUNT value of the Final Data Set to determine the sample size.

4.6.2. Obtain the appropriate Tolerance Interval Factor (TIF) for the size of the sample set. Table 1 lists the 95%/95% TIFs; refer to Standard statistical texts for other TIF multipliers. Note: TIFs other than 95%/95% must be specifically justified.

4.6.3. For a generic data analysis, multiple Tolerance Interval Factors may be used, providing a clear tabulation of results is included in the analysis, showing each value for the multiple levels of TIF.

4.6.4. Multiply the Tolerance Interval Factor by the standard deviation for the data points contained in the Final Data Set and by the Normality Adjustment Factor determined in the Coverage Analysis (if applicable).

4.6.5. If the analyzed drift term calculated above is applied to the existing calibration interval, application of additional drift uncertainty is not necessary.

4.6.6. When calculating drift for calibration intervals that exceed the historical calibration intervals, use the following equations, depending on whether the data is shown to be strongly time dependent or moderately time dependent.

For a Strongly Time Dependent random term, use the following equation.

$$DA_{Extended.random} = \sigma \times TIF \times NAF \times \frac{Max\_Rqd\_Time\_Interval}{Max\_FDS\_Time\_Interval}$$

For a Moderately Time Dependent random term, use the following equation. (Note that this equation is also generally used for cases where no time dependency is evident, because of the uncertainty in defining a drift value beyond analysis limits.)

$$DA_{Extended.random} = \sigma \times TIF \times NAF \times \sqrt{\frac{Max\_Rqd\_Time\_Interval}{Max\_FDS\_Time\_Interval}}$$

Where: σ = Standard Deviation of the Final Data Set

TIF = Tolerance Interval Factor from Table 1

NAF = Normality Adjustment Factor from the Coverage Analysis (If Applicable)

Max_FDS_Time_Interval = the maximum observed time interval within the Final Data Set

Max_Rqd_Time_Interval = the maximum time interval for desired calibration interval. For instance, 915 days for a desired 24 month nominal calibration interval.

4.6.7. Since random errors are always expressed as ± errors, specific consideration of directionality is not generally a concern. However, for bistables and switches, the directionality of any bias error must be carefully considered. Because of the fact that the As-Found and As-Left setpoints are recorded during calibration, the drift values determined up to this point in the Drift Calculation are representative of a drift in the setpoint, not in the indicated value.

Per Reference 7.1.2, error is defined as the algebraic difference between the indication and the ideal value of the measured signal. In other words,

Error = indicated value - ideal value (actual value)

For devices with analog outputs, a positive error means that the indicated value exceeds the actual value, which would mean that if a bistable or switching mechanism used that signal to produce an actuation on an increasing trend, the actuation would take place **prior to** the actual variable reaching the value of the intended setpoint. As analyzed so far in the Drift Calculation for bistables and switches, the drift causes the opposite effect. A positive Analyzed Drift would mean that the **setpoint** is higher than intended; thereby causing actuation to occur **after** the actual variable has exceeded the intended setpoint.

A bistable or switch can be considered to be a black box, which contains a sensing element or circuit and an ideal switching mechanism. At the time of actuation, the switch or bistable can be considered an indication of the process variable. Therefore, a positive shift of the setpoint can be considered to be a negative error. In other words, if the switch setting was intended to be 500 psig, but actually switched at 510 psig, at the time of the actuation, the switch "indicated" that the process value was 500 psig when the process value was actually 510 psig. Thus,

error = indicated value (500 psig) - actual value (510 psig) = -10 psig

Therefore, a positive shift of the setpoint on a switch or bistable is equivalent to a negative error, as defined by Reference 7.1.2. **Therefore, for clarity and consistency with the treatment of other bias error terms, the sign of the bias errors of a bistable or switch should be reversed, in order to comply with the convention established by Reference 7.1.2. In either case, the conclusions of the Drift Calculation should be clear enough for proper application to setpoint computations.**

5. CALCULATIONS

5.1. Drift Calculations

The Drift Calculations should be performed in accordance with the methodology described above, with the following documentation requirements.

5.1.1. The title includes the Manufacturer/Model number of the component group analyzed.

5.1.2. The calculation objective must:

5.1.2.1. describe, at a minimum, that the objective of the calculation is to document the drift analysis results for the component group, and extrapolate the drift value to the required calibration period (if applicable),

5.1.2.2. provide a list for the group of all pertinent information in tabular form (e.g. Tag Numbers, Manufacturer, Model Numbers, ranges and calibration spans), and

5.1.2.3. describe any limitations on the application of the results. For instance, if the analysis only applies to a certain range code, the objective should state this fact.

5.1.3. The method of solution should describe, at a minimum, a summary of the methodology used to perform the drift analysis outlined by this Design Guide. Exceptions taken to this Design Guide are to be included in this section including basis and references for any exceptions.

5.1.4. The actual calculation/analysis should provide:

5.1.4.1. A listing of data which was removed and the justification for removal

5.1.4.2. List of references

5.1.4.3. A narrative discussion of the specific activities performed for this calculation

5.1.4.4. Results and conclusions, including

- Manufacturer and model number analyzed
- Bias and random Analyzed Drift values, as applicable
- The applicable Tolerance Interval Factors (provide detailed discussion and justification if other than 95%/95%)
- Applicable drift time interval for application
- Normality conclusion
- Statement of time dependency observed, as applicable
- Limitations on the use of this value in application to uncertainty calculations, as applicable
- Limitations on the application if the results to similar instruments, as applicable

5.1.5. Attachment(s) should be provided, including the following information:

5.1.5.1. Input data with notes on removal and validity

5.1.5.2. Computation of drift data and calibration time intervals

5.1.5.3. Outlier summary, including Final Data Set and basic statistical summaries

5.1.5.4. Chi Square Test Results (As Applicable)

5.1.5.5. W Test or D' Test Results (As Applicable)

5.1.5.6. Coverage Analysis, Including Histogram, Percentages in the Required Sigma Band, and Normality Adjustment Factor (As Applicable)

5.1.5.7. Scatter Plot with Prediction Line and Equation

5.1.5.8. Binning Analysis Summaries for Bins and Plots (As Applicable)

5.1.5.9. Regression Plots, ANOVA Tables, and Critical F Values (As Applicable)

5.1.5.10. Derivation of the Analyzed Drift Values, With Summary of Conclusions

5.2. Setpoint/Uncertainty Calculations

To apply the results of the drift analyses to a specific device or loop, a setpoint or loop accuracy calculation must be performed, revised or evaluated in accordance with References 7.2.1 and 7.2.2, as appropriate. Per Section 3.2.1.2, the Analyzed Drift term characterizes various instrument uncertainty terms for the analyzed device, loop, or function. In order to save time, a comparison between these terms in an existing setpoint calculation to the Analyzed Drift can be made. If the terms within the existing calculation bound the Analyzed Drift term, then the existing calculation is conservative as is, and does not specifically require revision. If revision to the calculation is necessary, the Analyzed Drift term may be incorporated into the calculation, by replacing the appropriate terms for the analyzed devices with the Analyzed Drift term.

When comparing the results to setpoint calculations that have more than one device in the instrument loop that was analyzed for drift, comparisons can be made between the DA terms and the original terms on a device-by-device basis, or on a total loop basis. Care should be taken to properly combine terms for comparison in accordance with References 7.2.1 and 7.2.2, as appropriate.

When applying the Drift Calculation results of bistables or switches to a setpoint calculation, the preparer should fully understand the directionality of any bias terms within DA and apply the bias terms accordingly. (See Section 4.6.7.)

6. DEFINITIONS

95%/95%	Standard statistics term meaning that the results have a 95% confidence (γ) that at least 95% of the population will lie between the stated interval (P) for a sample size (n).	Ref. 7.1.1
Analyzed Drift (DA)	A term representing the errors determined by a completed drift analysis for a group. Uncertainties that ***may*** be represented by the analyzed drift term are component reference accuracy, input and output M&TE errors, personnel-induced or human related errors, ambient temperature and other environmental effects, power supply effects, misapplication errors and true component drift.	Section 4.6
As-Found (FT)	The condition in which a channel, or portion of a channel, is found after a period of operation and before recalibration.	Ref. 7.1.3
As-Left (CT)	The condition in which a channel, or portion of a channel, is left after calibration or final setpoint device verification.	Ref. 7.1.3
Bias (B)	A shift in the signal zero point by some amount.	Ref. 7.1.1
Calibrated Span (CS)	The maximum calibrated upper range value less the minimum calibrated lower range value.	Ref. 7.1.1
Calibration Interval	The elapsed time between the initiation or successful completion of calibrations or calibration checks on the same instrument, channel, instrument loop, or other specified system or device.	Ref. 7.1.1
Chi-Square Test	A test to determine if a sample appears to follow a given probability distribution. This test is used as one method for assessing whether a sample follows a normal distribution.	Ref. 7.1.1
Confidence Interval	An interval that contains the population mean to a given probability.	Ref. 7.1.1
Coverage Analysis	An analysis to determine whether the assumption of a normal distribution effectively bounds the data. A histogram is used to graphically portray the coverage analysis.	Ref. 7.1.1
Cumulative Distribution	An expression of the total probability contained within an interval from $-\infty$ to some value, x.	Ref. 7.1.1
D-Prime Test	A test to verify the assumption of normality for moderate to large sample sizes (50 or greater samples).	Ref. 7.1.1, 7.1.4
Dependent	In statistics, dependent events are those for which the probability of all occurring at once is different than the product of the probabilities of each occurring separately. In setpoint determination, dependent uncertainties are those uncertainties for which the sign or magnitude of one uncertainty affects the sign or magnitude of another uncertainty.	Ref. 7.1.1
Drift	An undesired change in output over a period of time where change is unrelated to the input, environment, or load.	Ref. 7.1.2
Error	The algebraic difference between the indication and the ideal value of the measured signal.	Ref. 7.1.2
Final Data Set (FDS)	The set of data that is analyzed for normality, time dependence, and used to determine the drift value. This data has all outliers and erroneous data removed, as allowed.	Section 3.6.3
Functionally Equivalent	Components with similar design and performance characteristics that can be combined to form a single population for analysis purposes.	Ref. 7.1.1
Histogram	A graph of a frequency distribution.	Ref. 7.1.1
Independent	In statistics, independent events are those in which the probability of all occurring at once is the same as the product of the probabilities of each occurring separately. In setpoint determination, independent uncertainties are those for which the sign or magnitude of one uncertainty does not affect the sign or magnitude of any other uncertainty.	Ref. 7.1.1

Instrument Channel	An arrangement of components and modules as required to generate a single protective action signal when required by a plant condition. A channel loses its identity where single protective action signals are combined.	Ref. 7.1.2
Instrument Range	The region between the limits within which a quantity is measured, received or transmitted, expressed by stating the lower and upper range values.	Ref. 7.1.2
Kurtosis	A characterization of the relative peakedness or flatness of a distribution compared to a normal distribution. A large kurtosis indicates a relatively peaked distribution and a small kurtosis indicates a relatively flat distribution.	Ref. 7.1.1
M&TE	Measurement and Test Equipment.	Ref. 7.1.1
Maximum Span	The component's maximum upper range limit less the maximum lower range limit.	Ref. 7.1.1
Mean	The average value of a random sample or population.	Ref. 7.1.1
Median	The value of the middle number in an ordered set of numbers. Half the numbers have values that are greater than the median and half have values that are less than the median. If the data set has an even number of values, the median is the average of the two middle values.	Ref. 7.1.1
Module	Any assembly of interconnected components that constitutes an identifiable device, instrument or piece of equipment. A module can be removed as a unit and replaced with a spare. It has definable performance characteristics that permit it to be tested as a unit.	Ref. 7.1.2
Normality Adjustment Factor	A multiplier to be used for the standard deviation of the Final Data Set to provide a drift model that adequately covers the population of drift points in the Final Data Set.	Section 3.7.5
Normality Test	A statistics test to determine if a sample is normally distributed.	Ref. 7.1.1
Outlier	A data point significantly different in value from the rest of the sample.	Ref. 7.1.1
Population	The totality of the observations with which we are concerned. A true population consists of all values, past, present and future.	Ref. 7.1.1
Probability	The branch of mathematics which deals with the assignment of relative frequencies of occurrence (confidence) of the possible outcomes of a process or experiment according to some mathematical function.	Ref. 7.3.2
Prob. Density Function	An expression of the distribution of probability for a continuous function.	Ref. 7.1.1
Probability Plot	A type of graph scaled for a particular distribution in which the sample data plots as approximately a straight line if the data follows that distribution. For example, normally distributed data plots as a straight line on a probability plot scaled for a normal distribution; the data may not appear as a straight line on a graph scaled for a different type of distribution.	Ref. 7.1.1
Proportion	A segment of a population that is contained by an upper and lower limit. Tolerance intervals determine the bounds or limits of a proportion of the population, not just the sampled data. The proportion (P) is the second term in the tolerance interval value (e.g. 95%/99%).	Ref. 7.3.2
Random	Describing a variable whose value at a particular future instant cannot be predicted exactly, but can only be estimated by a probability distribution function.	Ref. 7.1.1
Raw Data	As found minus As-Left calibration data used to characterize the performance of a functionally equivalent group of components.	Ref. 7.1.1
Reference Accuracy (AC)	A number or quantity that defines a limit that errors will not exceed when a device is used under specified operating conditions.	Ref. 7.1.2, 7.2.1, 7.2.2
Sample	A subset of a population.	Ref. 7.1.1

Sensor	The portion of an instrument channel that responds to changes in a plant variable or condition and converts the measured process variable into a signal; e.g., electric or pneumatic.	Ref. 7.1.2
Signal Conditioning	One or more modules that perform signal conversion, buffering, isolation or mathematical operations on the signal as needed.	Ref. 7.1.2
Skewness	A measure of the degree of symmetry around the mean.	Ref. 7.1.1
Span	The algebraic difference between the upper and lower values of a calibrated range.	Ref. 7.1.2
Standard Deviation	A measure of how widely values are dispersed from the population mean.	Ref. 7.1.1
Surveillance Interval	The elapsed time between the initiation or successful completion of a surveillance or surveillance check on the same component, channel, instrument loop, or other specified system or device.	Ref. 7.1.1
Time-Dependent Drift	The tendency for the magnitude of component drift to vary with time.	Ref. 7.1.1
Time-Dependent Drift Uncertainty	The uncertainty associated with extending calibration intervals beyond the range of available historical data for a given instrument or group of instruments.	Ref. 7.1.1
Time-Independent Drift	The tendency for the magnitude of component drift to show no specific trend with time.	Ref. 7.1.1
Tolerance	The allowable variation from a specified or true value.	Ref. 7.1.2
Tolerance Interval	An interval that contains a defined proportion of the population to a given probability.	Ref. 7.1.1
Trip Setpoint	A predetermined value for actuation of the final actuation device to initiate protective action.	Ref. 7.1.2
t-Test	For this Design Guide the t-Test is used to determine: 1) if a sample is an outlier of a sample pool, and 2) if two groups of data originate from the same pool.	Ref. 7.1.1
Uncertainty	The amount to which an instrument channel's output is in doubt (or the allowance made therefore) due to possible errors either random or systematic which have not been corrected for. The uncertainty is generally identified within a probability and confidence level.	Ref. 7.1.1
Variance	A measure of how widely values are dispersed from the population mean.	Ref. 7.1.1
W Test	A test to verify the assumption of normality for sample sizes less than 50.	Ref. 7.1.1, 7.1.4

7. REFERENCES

7.1. Industry Standards and Correspondence

7.1.1. EPRI TR-103335R1, "Statistical Analysis of Instrument Calibration Data - Guidelines for Instrument Calibration Extension/Reduction Programs," October, 1998

7.1.2. ISA-RP67.04.02-2000, "Recommended Practice, Methodologies for the Determination of Setpoints for Nuclear Safety-Related Instrumentation"

7.1.3. ANSI/ISA-S67.04.01-2000, "American National Standard, Setpoints for Nuclear Safety-Related Instrumentation"

7.1.4. ANSI N15.15-1974, "Assessment of the Assumption of Normality (Employing Individual Observed Values)"

7.1.5. NRC to EPRI Letter, "Status Report on the Staff Review of EPRI Technical Report TR-103335, "Guidelines for Instrument Calibration Extension/Reduction Program"," Dated March 1994

7.1.6. REGULATORY GUIDE 1.105, Rev. 2, "Instrument Setpoints"

7.1.7. GE NEDC 31336P-A "General Electric Instrument Setpoint Methodology"

7.1.8. US Nuclear Regulatory Commission Letter from Mr. Thomas H. Essig to Mr. R. W. James of Electric Power Research Institute, Dated December 1, 1997, "Status Report on the Staff Review of EPRI Technical Report TR-103335, 'Guidelines for Instrument Calibration Extension / Reduction Programs,' Dated March 1994"

7.2. Calculations and Programs

7.2.1. Engineering Department Guide EDG-EE-003, "Methodology for the Generation of Instrument Loop Uncertainty & Setpoint Calculations," Revision 0

7.2.2. Instrumentation and Control Standard GGNS-JS-09, "Methodology for the Generation of Instrument Loop Uncertainty & Setpoint Calculations," Revision 1

7.3. Miscellaneous

7.3.1. IPASS (Instrument Performance Analysis Software System), Revision 2.03, created by EDAN Engineering in conjunction with EPRI

7.3.2. Statistics for Nuclear Engineers and Scientists Part 1: Basic Statistical Inference, William J. Beggs; February, 1981

7.3.3. NRC Generic Letter 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24-Month Fuel Cycle"

7.3.4. Microsoft Excel for Microsoft Office 2003 (or Later Versions), Spreadsheet Program

Appendix A
Evaluation of the NRC Status Report on the Staff Review of EPRI Technical Report-103335, "Guidelines for Instrument Calibration Extension/Reduction Programs"

The following are excerpts or paraphrases from the NRC Status Report on the Staff review of EPRI Technical Report (TR)-103335, "Guidelines for Instrument Calibration Extension /Reduction Programs", dated March, 1994 (Reference 7.1.8). These excerpts are followed by the ***anticipated*** River Bend Station (RBS) and Grand Gulf Nuclear Station (GGNS) evaluation of how the Instrument Drift Analysis Design Guide for RBS and GGNS addresses the concern, as a part of the 24 Month Cycle Extension projects. ***The answers will need to be verified at the end of the projects, to ensure that all evaluations are correctly stated.***

STATUS REPORT

Item 4.1, Section 1, "Introduction", Second Paragraph:

"The staff has issued guidance on the second objective (evaluating extended surveillance intervals in support of longer fuel cycles) only for 18-month to 24-month refueling cycle extensions (GL 91-04). Significant unresolved issues remain concerning the applicability of 18 month (or less) historical calibration data to extended intervals longer than 24 months (maximum 30 months), and instrument failure modes or conditions that may be present in instruments that are unattended for periods longer than 24 months."

RBS/GGNS EVALUATION

Extensions for longer than 24 months are not to be requested via drift analysis in accordance with the Instrument Drift Analysis Design Guide.

STATUS REPORT

Item 4.2, Section 2, "Principles of Calibration Data Analysis", First Paragraph:

"This section describes the general relation between the as-found and as-left calibration values, and instrument drift. The term 'time dependent drift' is used. This should be clarified to mean time dependence of drift uncertainty, or in other words, time dependence of the standard deviation of drift of a sample or a population of instruments."

RBS/GGNS EVALUATION

Both the EPRI TR, Revisions 0 and 1 failed to adequately determine if there existed a relationship between the magnitude of drift and the time interval between calibrations. The drift analysis performed for RBS/GGNS looked at the time to magnitude relationship using several different statistical and non-statistical methods. First, during the evaluation of data for grouping, data was grouped for the same or similar manufacturer, model number, and application combinations even though the t' statistical test may have shown that the groups were not necessarily from the same population if the groups were performed on significantly different frequencies. This test grouping was made to ensure that the analysis did not cover-up a significant time dependent bias or random element magnitude shift.

Appendix A

Evaluation of the NRC Status Report on the Staff Review of EPRI Technical Report-103335, "Guidelines for Instrument Calibration Extension/Reduction Programs"

After the standard deviation and other simple statistics are calculated, the data is evaluated for the time to magnitude relationship. If adequately time-diverse data is available, a time-binning analysis is performed on the data. Data is divided into time bins, based on the time between calibrations. Statistics are computed for those bins, such as mean and standard deviation. These values are then plotted to expose any significant increases in the magnitude of the mean or standard deviation over time.

Regression analysis is performed, based on the scatter of the raw "drift" values and a second regression analysis is performed on the absolute values of the "drift." For each of these regression analyses, statistical tests are performed to determine if time dependency is evident. These statistical tests are the R^2, F, and P value tests.

Finally, visual examination of the plots generated as a result of the scatter plot, binning analysis, regression analysis of drift, and the regression analysis of the absolute value of drift are used to make a final judgment on whether or not the random or mean values of drift are time dependent. Therefore, the mean and random aspects of drift are evaluated for time dependency.

STATUS REPORT

Item 4.2, Section 2, "Principles of Calibration Data Analysis", Second Paragraph:

"Drift is defined as as-found – as-left. As mentioned in the TR this quantity unavoidably contains uncertainty contributions from sources other than drift. These uncertainties account for variability in calibration equipment and personnel, instrument accuracy, and environmental effects. It may be difficult to separate these influences from drift uncertainty when attempting to estimate drift uncertainty but this is not sufficient reason to group these allowances with a drift allowance. Their purpose is to provide sufficient margin to account for differences between the instrument calibration environment and its operating environment see Section 4.7 of this report for a discussion of combining other uncertainties into a 'drift' term."

RBS/GGNS EVALUATION

The drift determined by analysis was compared to the equivalent set of variables in the setpoint calculation. Per Section 3.2.1.2 of the RBS/GGNS Instrument Drift Analysis Design Guide, "The As-Found versus the As-Left data includes several sources of uncertainty over and above component drift. The difference between As-Found and previous As-Left data encompasses a number of instrument uncertainty terms in addition to drift, as defined by References 7.2.1 and 7.2.2, the setpoint calculation methodologies for RBS and GGNS. The drift is not assumed to encompass the errors associated with temperature effect, since the temperature difference between the two calibrations is not quantified, and is not anticipated to be significant. Additional instruction for the use of As-Found and As-Left data may be found in Reference 7.1.2." Therefore, the errors associated with the environment were not considered in the comparison of the Analyzed Drift values to the setpoint calculation values. The environmental effects are considered separately from the Analyzed Drift term, within the setpoint calculations.

STATUS REPORT

Appendix A

Evaluation of the NRC Status Report on the Staff Review of EPRI Technical Report-103335, "Guidelines for Instrument Calibration Extension/Reduction Programs"

Item 4.2, Section 2, "Principles of Calibration Data Analysis", Third Paragraph:

"The guidance of Section 2 is acceptable provided that time dependency of drift for a sample or population is understood to be time dependent [sic] of the uncertainty statistic describing the sample or population; e.g., the standard deviation of drift. A combination of other uncertainties with drift uncertainty may obscure any existing time dependency of drift uncertainty, and should not be done before time-dependency analysis is done."

RBS/GGNS EVALUATION

Time dependency evaluations were performed on the basic as-left/as-found data. Obviously other error contributors are contained in this data, but it is impossible to separate the contribution due to drift from the contribution due to Measurement and Test Equipment and Reference Accuracy. All of these terms will fully contribute to the observed errors. Using the raw values appears to give the most reliable interpretation of the time dependency for the calibration process, which is the true value of interest. No other uncertainties are combined with the basic as-left/as-found data for time dependency determination.

STATUS REPORT

Item 4.3, Section 3, "Calibration Data Collection", Second Paragraph:

"When grouping instruments, as well as manufacturer make and model, care should be taken to group only instruments that experience similar environments and process effects. Also, changes in manufacturing method, sensor element design, or the quality assurance program under which the instrument was manufactured should be considered as reasons for separating instruments into different groups. Instrument groups may be divided into subgroups on the basis of instrument age, for the purpose of investigating whether instrument age is a factor in drift uncertainty."

RBS/GGNS EVALUATION

Instruments were originally grouped based on manufacturer make, model number, and specific range of setpoint or operation. The groups were then evaluated and combined based on Sections 3.5.1 through 3.5.4 of the design guide. The appropriateness of the grouping was then tested based on a t-Test (two samples assuming unequal variances). The t-Test defines the probability, associated with a Student's t-Test; that two samples are likely to have come from the same underlying population. Instrument groups were not divided into subgroups based on age.

Appendix A

Evaluation of the NRC Status Report on the Staff Review of EPRI Technical Report-103335, "Guidelines for Instrument Calibration Extension/Reduction Programs"

STATUS REPORT

Item 4.3, Section 3, "Calibration Data Collection", Second Paragraph (continued):

"Instrument groups should also be evaluated for historical instrument anomalies or failure modes that may not be evident in a simple compilation of calibration data. This evaluation should confirm that almost all instruments in a group performed reliably and almost all required only calibration attendance."

RBS/GGNS EVALUATION

A separate surveillance test failure evaluation is performed for the procedures implementing the surveillance requirements. This evaluation identifies calibration-related and non-calibration-related failures for single instruments, and groups of instruments supporting a specific function. After all relevant device and multiple device failures were identified, a cross-check of failures across manufacturer make and model number was also performed to determine if common mode failures could present a problem for the cycle extension. This evaluation confirmed that almost all instruments in a group (associated with extended Technical Specification line items) performed reliably and most failures were detected by more frequent testing.

STATUS REPORT

Item 4.3, Section 3, "Calibration Data Collection", Third Paragraph:

"Instruments within a group should be investigated for factors that may cause correlation between calibrations. Common factors may cause data to be correlated, including common calibration equipment, same personnel performing calibrations, and calibrations occurring in the same conditions. The group, not individual instruments within the group, should be tested for trends."

RBS/GGNS EVALUATION

Instruments are only investigated for correlation factors where multiple instruments appeared to have been driven out of tolerance by a single factor. Correlation may exist between the specific type of test equipment (e.g., Fluke 863 on the 0-200 mV range) and the personnel performing calibrations for each plant. This correlation would only affect the measurement if it caused the instrument performance to be outside expected boundaries, e.g., where additional errors should be considered in the setpoint analysis or where it showed a defined bias. Because Measurement and Test Equipment (M&TE) is calibrated more frequently than most process components being monitored, the effect of test equipment between calibrations is considered to be negligible and random. The setting tolerance, readability, and other factors which are more personnel-based, would only affect the performance if there was a predisposition to leave or read settings in a particular direction (e.g., always in the more conservative direction). Plant training and evaluation programs are designed to eliminate this type of predisposition. Therefore, the correlation between M&TE and instrument performance; or between personnel and instrument performance has not been evaluated. Observed as-found values outside the allowable tolerance [Leave-As-Is-Zone (LAIZ) or Allowable Value] were evaluated to determine if a common cause existed as a part of the data entry evaluation.

STATUS REPORT

Item 4.3, Section 3, "Calibration Data Collection", Fourth Paragraph:

"TR-103335, Section 3.3, advises that older data may be excluded from analysis. It should be emphasized that when selecting data for drift uncertainty time dependency analysis it is unacceptable to exclude data simply because it is old data. When selecting data for drift uncertainty time dependency analysis, the objective should be to include data for time spans at least as long as the proposed extended calibration interval, and preferably, several times as long, including calibration intervals as long as the proposed interval. For limited extensions (e.g., a GL 91-04 extension), acceptable ways to obtain this longer interval data include obtaining data from other nuclear-plants or from other industries for identical or close-to-identical instruments, or combining intervals between which the instrument was not reset or adjusted. If data from other sources is used, the source should be analyzed for similarity to the target plant in procedures, process, environment methodology, test equipment, maintenance schedules and personnel training. An appropriate conclusion of the data collection process may be that there is insufficient data of appropriate time span for a sufficient number of instruments to support statistical analysis of drift uncertainty time dependency."

RBS/GGNS EVALUATION

Data was selected for the last 90 months (5 cycles). This data allowed for the evaluation of data with various different calibration spans over several calibration intervals to provide representative information for each type of instrument. Data from outside the RBS/GGNS data set was not used to provide longer interval data. In most cases the time dependency determination was based on calibrations performed at or near 18 months and data performed at shorter intervals (monthly, quarterly, or semiannually). There did not appear to be any time based factors that would be present from 18 to 24 months that would not have been present between 1, 3, 6, or 12 and 18 months. It could be determined that there is insufficient data to support statistical analysis of drift time dependency. For these cases, a correlation between drift magnitude and time is assumed and the calculation reflects time dependent drift values.

STATUS REPORT

Item 4.3, Section 3, "Calibration Data Collection", Fifth Paragraph:

"TR-103335, Section 3.3 provides guidance on the amount of data to collect. As a general rule, it is unacceptable to reject applicable data, because biases in the data selection process may introduce biases in the calculated statistics. There are only two acceptable reasons for reducing the amount of data selected: enormity, and statistical dependence. When the number of data points is so enormous that the data acquisition task would be prohibitively expensive, a randomized selection process, not dependent upon engineering judgment, should be used. This selection process should have three steps. In the first step, all data is screened for applicability, meaning that all data for the chosen instrument grouping is selected, regardless of the age of the data. In the second step, a proportion of the applicable data is chosen by automated random selection, ensuring that the data records for single instruments are complete, and enough individual instruments are included to constitute a statistically diverse sample. In the third step, the first two steps are documented. Data points should be combined when there is indication that they are statistically dependent on each other, although alternate approaches may be acceptable. See Section 4.5, below, on 'combined point' data selection and Section 4.4.1 on '0%, 25%, 50%, 75%, and 100% calibration span points'."

RBS/GGNS EVALUATION

A time interval of 90 months was selected as representative based on RBS/GGNS operating history. No data points were rejected from this time interval, and no sampling techniques were used.

STATUS REPORT

Item 4.4, Section 4, "Analysis of Calibration Data":

Sub-item, 4.4.1, Sections 4.3 and 4.4, Data Setup and Spreadsheet Statistics, First Paragraph:

"The use of spreadsheets, databases, or other commercial software is acceptable for data analysis provided that the software, and the operating system used on the analysis computer, is under effective configuration control. Care should be exercised in the use of Windows or similar operating systems because of the dependence on shared libraries. Installation of other application software on the analysis machine can overwrite shared libraries with older versions or versions that are inconsistent with the software being used for analysis."

RBS/GGNS EVALUATION

The project used the Microsoft EXCEL spreadsheets to perform the drift analysis. This software was not treated as QA software. Therefore, computations were verified using hand verification and alternate software on different computers, such as EPRI Instrument Performance Analysis Software System (IPASS), Revision 2 and Lotus 1-2-3 spreadsheets.

STATUS REPORT

Item 4.4, Section 4, "Analysis of Calibration Data":

Sub-item, 4.4.1, Sections 4.3 and 4.4, Data Setup and Spreadsheet Statistics, Second Paragraph:

"Using either engineering units or per-unit (percent of span) quantities is acceptable. The simple statistic calculations (mean, sample standard deviation, sample size) are acceptable. Data should be examined for correlation or dependence to eliminate over-optimistic tolerance interval estimates. For example, if the standard deviation of drift can be fitted with a regression line through the 0%, 25%, 50%, 75%, and 100% calibration span points, there is reason to believe that drift uncertainty is correlated over the five (or nine, if the data includes a repeatability sweep) calibration data points. An example is shown in TR-

103335, Figure 5.4, and a related discussion is given in TR-103335 Section 5.1.3. Confidence/tolerance estimates are based on (a) an assumption of normality (b) the number of points in the data set, and (c) the standard deviation of the sample. Increasing the number of points (utilizing each calibration span point) when data is statistically dependent decreases the tolerance factor k, which may falsely enhance the confidence in the predicted tolerance interval. To retain the information, but achieve a reasonable point count for confidence/tolerance estimates, the statistically dependent data points should be combined into a composite data point. This retains the information but cuts the point count. For drift uncertainty estimates with data similar to that in the TR example, an acceptable method requires that the number of independent data points should be one-fifth (or one ninth) of the total number of data points in the example and a combined data point for each set of five span points should be selected that is representative of instrument performance at or near the span point most important to the purpose of the analysis (i.e., trip or normal operation point)."

RBS/GGNS EVALUATION

The analysis for RBS/GGNS used either engineering units or percent of calibrated span as appropriate to the calibration process. As an example, for switches that do not have a realistic span value, the engineering units were used in the analyses; for analog devices, normally percent of span is used. The data was evaluated for dependence, normally dependence was found between points (0%, 25%, 50%, 75%, and 100%) for a single calibration. However, due to the changes in M&TE and personnel performing the calibrations, independence was found between calibrations of the same component on different dates. To ensure conservatism, the most conservative simple statistic values for the points closest to the point of interest are selected, or the most conservative values for any data point are selected. The multiplier is determined based on the number of actual calibrations associated with the worst-case value selected. Selection of the actual number of calibrations is equivalent to the determination of independent points (e.g., one fifth or one ninth of the total data point count). Selection of the worst-case point is also more conservative than the development of a combined data point.

STATUS REPORT

Item 4.4, Section 4, "Analysis of Calibration Data":

Sub-item 4.4.2, Section 4.5, Outlier Analysis:

"Rejection of outliers is acceptable only if a specific, direct reason can be documented for each outlier rejected. For example, a documented tester failure would be cause for rejecting a calibration point taken with the tester when it had failed. It is not acceptable to reject outliers on the basis of statistical tests alone. Multiple passes of outlier statistical criterion are not acceptable. An outlier test should only be used to direct attention to data points, which are then investigated for cause. Five acceptable reasons for outlier rejection provided that they can be demonstrated, are given in the TR: data transcription errors, calibration errors, calibration equipment errors, failed instruments, and design deficiencies. Scaling or setpoint changes that are not annotated in the data record indicate unreliable data, and detection of unreliable data is not cause for outlier rejection, but may be cause for rejection of the entire data set and the filing of a licensee event report. The usual engineering technique of annotating the raw data record with the reason for rejecting it, but not obliterating the value, should be followed. The rejection of outliers typically has cosmetic effects: if sufficient data exists, it makes the results look slightly better; if insufficient data exists, it may mask a real trend. Consequently, rejection of outliers should be done with extreme caution and should be viewed with considerable suspicion by a reviewer."

RBS/GGNS EVALUATION

It is acceptable to remove one outlier from an analysis based on statistical means, other than those using the engineering judgments mentioned in the EPRI document. The Design Guide is written with this as a general rule. This does not reduce the amount of scrutiny that the preparer and reviewer use in the entry and evaluation of the calibration data. The intent is to properly model device performance after completion of this project. No more than one outlier is removed from the drift population on the basis of being outliers. Given very large sample sizes or complicated calibration processes, specific diagnosis of problems when reviewing procedure data is sometimes not possible. However, the data can contain errors which are very likely to be unrelated to drift or device performance, which should be removed, given an appropriate consideration from both the preparer and reviewer. For this project, rejection of outliers was performed with extreme caution and was viewed with considerable suspicion by the reviewer.

Significant conservatisms exist in the assumptions for extrapolation of drift values as computed per this Design Guide, which provide additional margin for the devices to drift. Additionally, if the removal of the data reduced the computed extrapolated drift to a value that is not consistent with the capability of the device, the improved drift-monitoring program will detect the problem and implement design activity, maintenance activity, or both to correct the problem.

STATUS REPORT

Item 4.4, Section 4, "Analysis of Calibration Data":

Sub-item 4.4.3, Section 4.6, "Verifying the Assumption of Normality":

"The methods described are acceptable in that they are used to demonstrate that calibration data or results are calculated as if the calibration data were a sample of a normally distributed random variable. For example, a tolerance interval which states that there is a 95% probability that 95% of a sample drawn from a population will fall within tolerance bounds is based on an assumption of normality, or that the population distribution is a normal distribution. Because the unwarranted removal of outliers can have a significant effect on the normality test, removal of significant numbers of, or sometimes any (in small populations), outliers may invalidate this test."

Appendix A
Evaluation of the NRC Status Report on the Staff Review of EPRI Technical Report-103335, "Guidelines for Instrument Calibration Extension/Reduction Programs"

RBS/GGNS EVALUATION

The methods that were found acceptable were used for the RBS/GGNS analysis. All drift studies involved the removal of one or less outliers. Therefore, the normality tests are still valid. Coverage analysis was used where the normality tests did not confirm the assumption of normality. This produces a conservative model of the drift data by expanding the standard deviation to provide adequate coverage.

STATUS REPORT

Item 4.4, Section 4, "Analysis of Calibration Data":

Sub-item 4.4.4, Section 4.7, "Time-Dependent Drift Considerations", First through Ninth Paragraphs:

"This section of the TR discusses a number of methods for detecting a time dependency in drift data, and one method of evaluating drift uncertainty time dependency. None of the methods uses a formal statistical model for instrument drift uncertainty, and all but one of them focus on drift rather than drift uncertainty. Two conclusions are inescapable: regression analysis cannot distinguish drift uncertainty time dependency, and the slope and intercept of regression lines may be artifacts of sample size, rather than being statistically significant. Using the results of a regression analysis to rule out time dependency of drift uncertainty is circular reasoning: i.e., regression analysis eliminates time dependency of uncertainty; no time dependency is found; therefore, there is no time dependency."

RBS/GGNS EVALUATION

Several different methods of evaluation for time dependency of the data are used for the analysis. One method, the binning analysis, is to evaluate the standard deviations at different calibration intervals. This analysis technique is the most recommended method of determining time-dependent tendencies in a given sample pool. The test consists simply of segregating the drift data into different groups (bins) corresponding to different ranges of calibration or surveillance intervals, and comparing the standard deviations for the data in the various groups. The purpose of this type of analysis is to determine if the standard deviation or mean tends to become larger as the time between calibration increases. Simple regression lines, regression of the absolute value of drift, as well as R^2, F, and P tests are also generated and reviewed. Finally visual examinations of the scatter plot, binning plot, and both regression plots are used to assess or corroborate results. Where there is not sufficient data to perform the detailed evaluation, the data is assumed moderately time dependent. Whenever extrapolation of the drift value is required, in ALL cases, drift is assumed to be at least moderately time dependent for the purposes of extrapolation, even though many of the test results may show that the drift is time independent.

Appendix A

Evaluation of the NRC Status Report on the Staff Review of EPRI Technical Report-103335, "Guidelines for Instrument Calibration Extension/Reduction Programs"

STATUS REPORT

Item 4.4, Section 4, "Analysis of Calibration Data":

Sub-item 4.4.4, Section 4.7, "Time-Dependent Drift Considerations", Thirteenth and Fourteenth Paragraphs:

"A model can be used either to bound or project future values for the quantity in question (drift uncertainty) for extended intervals. An acceptable method would use standard statistical methods to show that a hypothesis (that the instruments under study have drift uncertainties bounded by the drift uncertainty predicted by a chosen model) is true with high probability. Ideally, the method should use data that include instruments that were un-reset for at least as long as the intended extended interval, or similar data from other sources for instruments of like construction and environmental usage. The use of data of appropriate time span is preferable; however, if this data is unavailable, model projection may be used provided the total projected interval is no greater than 30 months and the use of the model is justified. A follow-up program of drift monitoring should confirm that model projections of uncertainty bounded the actual estimated uncertainty. If it is necessary to use generic instrument data or constructed intervals, the chosen data should be grouped with similar grouping criteria as are applied to instruments of the plant in question, and Student's "t" test should be used to verify that the generic or constructed data mean appears to come from the same population. The "F" test should be used on the estimate of sample variance. For a target surveillance interval constructed of shorter intervals where instrument reset did not occur, the longer intervals are statistically dependent upon the shorter intervals; hence, either the constructed longer-interval data or the shorter-interval data should be used, but not both. In a constructed interval, drift = as-left$_{(0)}$ – as found$_{(LAST)}$, the intermediate values are not used.

When using samples acquired from generic instrument drift analyses or constructed intervals, the variances are not simply summed, but are combined weighted by the degrees of freedom in each sample."

RBS/GGNS EVALUATION

The General Electric interval extension process is used because RBS/GGNS is committed to the General Electric Setpoint Methodology. Where the drift can be proven to be time independent for the analysis period, or shown to be only slightly or moderately time dependent, the calculated drift value is extended based on the formula:

$$\text{Drift}_{30} = \text{Drift calculated} * (30/\text{calculated drift time interval})^{1/2}.$$

Where there is a strong indication of time dependent drift, the following formula is used:

$$\text{Drift}_{30} = \text{Drift calculated} * (30/\text{calculated drift time interval}).$$

Appendix A

Evaluation of the NRC Status Report on the Staff Review of EPRI Technical Report-103335, "Guidelines for Instrument Calibration Extension/Reduction Programs"

STATUS REPORT

Item 4.4, Section 4, "Analysis of Calibration Data":

Sub-item 4.4.5, Section 4.8, "Shelf Life of Analysis Results":

"The TR gives guidance on how long analysis results remain valid. The guidance given is acceptable with the addition that once adequate analysis and documentation is presented and the calibration interval extended, a strong feedback loop must be put into place to ensure drift, tolerance and operability of affected components are not negatively impacted. An analysis should be re-performed if its predictions turn out to exceed predetermined limits set during the calibration interval extension study. A goal during the re-performance should be to discover why the analysis results were incorrect The establishment of a review and monitoring program, as indicated in GL 91-04, Enclosure 2, Item 7 is crucial to determining that the assumptions made during the calibration interval extension study were true. The methodology for obtaining reasonable and timely feedback must be documented."

RBS/GGNS EVALUATION

RBS/GGNS is committed to establish a trending program to provide feedback on the acceptability of the drift error extension. This program will evaluate any as-found condition outside the Leave-As-Is-Zone (LAIZ) and perform a detailed analysis of as-found values outside the Allowable Value. The drift analysis will be re-performed when the root cause analysis indicates drift is a probable cause for the performance problems.

STATUS REPORT

Item 4.5, Section 5, "Alternative Methods of Data Collection and Analysis":

"Section 5 discusses two alternatives to as-found/as-left (AFAL) analysis, combining the 0%, 25%, 50%, 75% and 100% span calibration points, and the EPRI Instrument Calibration Reduction Program (ICRP).

Two alternatives to AFAL are mentioned: as-found/setpoint (AFSP) analysis and worse case as-found/as-left (WCAFAL). Both AFSP and WCAFAL are more conservative than the AFAL method because they produce higher estimates of drift. Therefore, they are acceptable alternatives to AFAL drift estimation.

The combined-point method is acceptable, and in some cases preferable, if the combined value of interest is taken at the point important to the purpose of the analysis. That is, if the instrument being evaluated is used to control the plant in an operating range, the instrument should be evaluated near its operating point. If the instrument being evaluated is employed to trip the reactor, the instrument should be evaluated near the trip point. The combined-point method should be used if the statistic of interest shows a correlation between calibration span points, thus inflating the apparent number of data points

Appendix A

Evaluation of the NRC Status Report on the Staff Review of EPRI Technical Report-103335, "Guidelines for Instrument Calibration Extension/Reduction Programs"

and causing an overstatement of confidence in the results. The method by which the points are combined (e.g., nearest point interpolation, averaging) should be justified and documented."

RBS/GGNS EVALUATION

The worst-case as-found/as-left method can be used to verify manufacturer drift specifications, or to establish drift, where there is insufficient data to perform a rigorous drift analysis. The WCAFAL would be evaluated against current allowances and manufacturer specifications. If the observed drift values are bounded, then manufacturer specifications or current drift allowances are extrapolated to a surveillance interval of 30 months.

STATUS REPORT

Item 4.6, Section 6, "Guidelines for Calibration and Surveillance Interval Extension Programs":

"This section presents an example analysis in support of extending the surveillance interval of reactor trip bistables from monthly to quarterly. Because these bistables exhibit little or no bias, and very small drift, the analysis example does not challenge the methodology presented in TR-103335 Section 4, and thus raises no acceptability issues related to drift analysis that have not already been covered. The bistables are also rack instruments, and thus not representative of process instruments, for which drift is a greater concern. Bistables do not produce a variable output signal that can be compared to redundant device readings by operations personnel, or during trending programs, and cannot be compared during channel checks, as redundant process instruments are. For these reasons the data presented in Section 6 have very little relationship to use in the TR methodology for calibration interval extensions for process instruments. The binomial pass/fail methodology of Section 6.3 is acceptable as a method of complying with GL 91-04, Enclosure 2, item 1 for bistables, "Confirm that acceptable limiting values of drift have not been exceeded except in rare instances." This method provides guidance for the definition of "rare" instances by describing how to compute expected numbers of exceedances for an assumed instrument confidence / tolerance criterion (e.g., 95/95) for a large set of bistable data. There are other methods that would be acceptable, in particular, the X^2 test for significance.

This test can be used to determine if the exceedance-of-allowable-limits frequency in the sample is probably due to chance or probably not due to chance, for a given nominal frequency (e.g., 95% of drifts do not exceed allowable limits). This provides an acceptable method of complying with GL 91-04, Enclosure 2, item 1 in the general case."

RBS/GGNS EVALUATION

RBS/GGNS does not plan to extend any bistables from monthly to quarterly. Therefore, this section is not evaluated for the 24-Month cycle extension project.

Appendix A

Evaluation of the NRC Status Report on the Staff Review of EPRI Technical Report-103335, "Guidelines for Instrument Calibration Extension/Reduction Programs"

STATUS REPORT

Item 4.7, Section 7, "Application to Instrument Setpoint Programs":

"Section 7 is a short tutorial on combining uncertainties in instrument Setpoint calculations. Figure 7-1 of this section is inconsistent with ANSI/ISA-S67.04-1994, Part 1, Figure 1. Rack uncertainty is not combined with sensor uncertainty in the computation of the allowable value in the standard. The purpose of the allowable value is to set a limit beyond which there is reasonable probability that the assumptions used in the setpoint calculation were in error. For channel functional tests, these assumptions normally do not include an allowance for sensor uncertainty (quarterly interval, sensor normally excluded). If a few instruments exceed the allowable value, this is probably due to instrument malfunction. If it happens frequently, the assumptions in the setpoint analysis may be wrong. Since the terminology used in Figure 7-1 is inconsistent with ANSI/ISA-S67.04-1994, Part I, Figure 1, the following correspondences are suggested: the 'Nominal Trip Setpoint' is the ANSI/ISA trip setpoint; ANSI/ISA value 'A' is the difference between TR 'Analytical Limit' and 'Nominal Trip Setpoint' [sic]; 'Sensor Uncertainty' is generally not included in the 'Allowable Value Uncertainty' and would require justification, the difference between 'Allowable Value' and 'Nominal Trip Setpoint' is ANSI/ISA value 'B'; the 'Leave-As-Is-Zone' is equivalent to the ANSI/ISA value 'E' and the difference between 'System Shutdown' and 'Nominal Trip Setpoint' is the ANSI/ISA value 'D'. Equation 7-5 (page 7-7 of the TR) combines a number of uncertainties into a drift term, D. If this is done, the reasons and the method of combination should be justified and documented. The justification should include an analysis of the differences between operational and calibration environments, including accident environments in which the instrument is expected to perform."

RBS/GGNS EVALUATION

Application of the drift values to plant setpoints is performed in accordance with the GE Setpoint Methodology and per EDG-EE-003, the RBS/GGNS setpoint methodology document. The Allowable Value defined for the GE Setpoint Methodology is defined as the operability limit when performing the channel calibration. Therefore, the Allowable Value placed in Technical Specification includes the sensor drift for the refueling cycle and the trip unit drift (for transmitter/trip unit combinations) for the quarter (or other surveillance interval at which the trip unit is calibrated). No environmental terms are considered to be included in the drift term.

Appendix A

Evaluation of the NRC Status Report on the Staff Review of EPRI Technical Report-103335, "Guidelines for Instrument Calibration Extension/Reduction Programs"

STATUS REPORT

Item 4.8, Section 8, "Guidelines for Fuel Cycle Extensions":

"The TR repeats the provisions of Enclosure 2, GL 91-04, and provides direct guidance, by reference to preceding sections of the TR, on some of them."

RBS/GGNS EVALUATION

A specific discussion of how the RBS/GGNS evaluations meet the guidance of GL 91-04 will be provided in the licensing submittal for the 24 Month Cycle Extension project.

Attachment 7
RBG-46932

Applicable Instrumentation

Requirement	Mark No.	Calculation	Manufacturer	Model No.
SR 3.3.1.1.13-3	B21-N678A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.1.1.13-3	B21-N678B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.1.1.13-3	B21-N678C	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.1.1.13-3	B21-N678D	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.1.1.13-3	B21-N679A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.1.1.13-3	B21-N679B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.1.1.13-3	B21-N679C	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.1.1.13-3	B21-N679D	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.1.1.13-3	B21-N078A	G13.18.6.3-021	ROSEMOUNT	1152GP9E22T0280 PB
SR 3.3.1.1.13-3	B21-N078B	G13.18.6.3-021	ROSEMOUNT	1152GP9E22T0280 PB
SR 3.3.1.1.13-3	B21-N078C	G13.18.6.3-021	ROSEMOUNT	1152GP9E22T0280 PB
SR 3.3.1.1.13-3	B21-N078D	G13.18.6.3-021	ROSEMOUNT	1152GP9E22T0280 PB
SR 3.3.1.1.13-4	B21-N680A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.1.1.13-4	B21-N680B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.1.1.13-4	B21-N680C	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.1.1.13-4	B21-N680D	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.1.1.13-4	B21-N683A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.1.1.13-4	B21-N683B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.1.1.13-4	B21-N683C	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.1.1.13-4	B21-N683D	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.1.1.13-4	B21-N080A	G13.18.6.3-018	ROSEMOUNT	1152DP4E22T0280 PB
SR 3.3.1.1.13-4	B21-N080B	G13.18.6.3-018	ROSEMOUNT	1152DP4E22T0280 PB
SR 3.3.1.1.13-4	B21-N080C	G13.18.6.3-018	ROSEMOUNT	1152DP4E22T0280 PB
SR 3.3.1.1.13-4	B21-N080D	G13.18.6.3-018	ROSEMOUNT	1153DB4N0037
SR 3.3.1.1.13-5	B21-N680A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.1.1.13-5	B21-N680B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.1.1.13-5	B21-N680C	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.1.1.13-5	B21-N680D	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.1.1.13-5	B21-N683A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.1.1.13-5	B21-N683B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.1.1.13-5	B21-N683C	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.1.1.13-5	B21-N683D	G13.18.6.3-015	ROSEMOUNT	510DU

SR 3.3.1.1.13-5	B21-N080A	G13.18.6.3-018	ROSEMOUNT	1152DP4E22T0280 PB
SR 3.3.1.1.13-5	B21-N080B	G13.18.6.3-018	ROSEMOUNT	1152DP4E22T0280 PB
SR 3.3.1.1.13-5	B21-N080C	G13.18.6.3-018	ROSEMOUNT	1152DP4E22T0280 PB
SR 3.3.1.1.13-5	B21-N080D	G13.18.6.3-018	ROSEMOUNT	1153DB4N0037
SR 3.3.1.1.13-7	C71-N650A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.1.1.13-7	C71-N650B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.1.1.13-7	C71-N650C	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.1.1.13-7	C71-N650D	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.1.1.13-7	C71-N651	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.1.1.13-7	C71-N653	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.1.1.13-7	C71-N050A	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.1.1.13-7	C71-N050B	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.1.1.13-7	C71-N050C	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.1.1.13-7	C71-N050D	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.1.1.13-8.a	C11-N012A	G13.18.6.3-002	GOULD INC (FORMERLY ITE I	PD-3218
SR 3.3.1.1.13-8.a	C11-N012B	G13.18.6.3-002	GOULD INC (FORMERLY ITE I	PD-3218
SR 3.3.1.1.13-8.a	C11-N012C	G13.18.6.3-002	GOULD INC (FORMERLY ITE I	PD-3218
SR 3.3.1.1.13-8.a	C11-N012D	G13.18.6.3-002	GOULD INC (FORMERLY ITE I	PD-3218
SR 3.3.1.1.13-8.a	C11-N601A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.1.1.13-8.a	C11-N601B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.1.1.13-8.a	C11-N601C	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.1.1.13-8.a	C11-N601D	G13.18.6.3-015	ROSEMOUNT	PD3218
SR 3.3.1.1.13-10	C71-N005A	G13.18.6.3-011	BARKSDALE CNTRL/DIV TRANS	TC9622-3
SR 3.3.1.1.13-10	C71-N005B	G13.18.6.3-011	BARKSDALE CNTRL/DIV TRANS	TC9622-3
SR 3.3.1.1.13-10	C71-N005C	G13.18.6.3-011	BARKSDALE CNTRL/DIV TRANS	TC9622-3
SR 3.3.1.1.13-10	C71-N005D	G13.18.6.3-011	BARKSDALE CNTRL/DIV TRANS	TC9622-3
SR 3.3.1.1.13-10	C71-N652A	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P216026
SR 3.3.1.1.13-10	C71-N652B	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P216026
SR 3.3.1.1.13-10	C71-N652C	G13.18.6.3-015	ROSEMOUNT	164C5150P216026
SR 3.3.1.1.13-10	C71-N652D	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P216026

SR 3.3.1.1.13-10	C71-N052A	G13.18.6.3-021	ROSEMOUNT	1152GP9N22T0280 PB
SR 3.3.1.1.13-10	C71-N052B	G13.18.6.3-021	ROSEMOUNT	1152GP9N22T0280 PB
SR 3.3.1.1.13-10	C71-N052C	G13.18.6.3-021	ROSEMOUNT	1153GB9RBN0037
SR 3.3.1.1.13-10	C71-N052D	G13.18.6.3-021	ROSEMOUNT	1152GP9E22T0280 PB
SR 3.3.1.1.16-9	C71-N652A	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P216026
SR 3.3.1.1.16-9	C71-N652B	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P216026
SR 3.3.1.1.16-9	C71-N652C	G13.18.6.3-015	ROSEMOUNT	164C5150P216026
SR 3.3.1.1.16-9	C71-N652D	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P216026
SR 3.3.1.1.16-9	C71-N052A	G13.18.6.3-021	ROSEMOUNT	1152GP9N22T0280 PB
SR 3.3.1.1.16-9	C71-N052B	G13.18.6.3-021	ROSEMOUNT	1152GP9N22T0280 PB
SR 3.3.1.1.16-9	C71-N052C	G13.18.6.3-021	ROSEMOUNT	1153GB9RBN0037
SR 3.3.1.1.16-9	C71-N052D	G13.18.6.3-021	ROSEMOUNT	1152GP9E22T0280 PB
SR 3.3.1.1.16-10	C71-N652A	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P216026
SR 3.3.1.1.16-10	C71-N652B	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P216026
SR 3.3.1.1.16-10	C71-N652C	G13.18.6.3-015	ROSEMOUNT	164C5150P216026
SR 3.3.1.1.16-10	C71-N652D	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P216026
SR 3.3.1.1.16-10	C71-N052A	G13.18.6.3-021	ROSEMOUNT	1152GP9N22T0280 PB
SR 3.3.1.1.16-10	C71-N052B	G13.18.6.3-021	ROSEMOUNT	1152GP9N22T0280 PB
SR 3.3.1.1.16-10	C71-N052C	G13.18.6.3-021	ROSEMOUNT	1153GB9RBN0037
SR 3.3.1.1.16-10	C71-N052D	G13.18.6.3-021	ROSEMOUNT	1152GP9E22T0280 PB
SR 3.3.1.1.17-2.b	B33-N014A	G13.18.6.3-023	ROSEMOUNT	1152DP5E22T0280 PB
SR 3.3.1.1.17-2.b	B33-N014B	G13.18.6.3-023	ROSEMOUNT	1152DP5E22T0280 PB
SR 3.3.1.1.17-2.b	B33-N014C	G13.18.6.3-023	ROSEMOUNT	1152DP5E22T0280 PB
SR 3.3.1.1.17-2.b	B33-N014D	G13.18.6.3-023	ROSEMOUNT	1152DP5E22T0280 PB
SR 3.3.1.1.17-2.b	B33-N024A	G13.18.6.3-023	ROSEMOUNT	1153DB5PA
SR 3.3.1.1.17-2.b	B33-N024B	G13.18.6.3-023	ROSEMOUNT	1152DP5E22T0280 PB

SR 3.3.1.1.17-2.b	B33-N024C	G13.18.6.3-023	ROSEMOUNT	1152DP5E22T0280 PB
SR 3.3.1.1.17-2.b	B33-N024D	G13.18.6.3-023	ROSEMOUNT	1152DP5E22T0280 PB
SR 3.3.3.1.3-2	B21-N091A	G13.18.6.3-018	ROSEMOUNT	1154DP5RBN0037
SR 3.3.3.1.3-2	B21-LTN091B	G13.18.6.3-018	ROSEMOUNT	1154DP5RBN0037
SR 3.3.3.2.3-10	E51-FYK601	G13.18.6.3-015	GENERAL ELECTRIC CO	159C4486P001
SR 3.3.3.2.3-10	E51-FTN003	G13.18.6.3-023	ROSEMOUNT	1153DB5RCN0037
SR 3.3.4.1.3-b	C71-N005A	G13.18.6.3-011	BARKSDALE CNTRL/DIV TRANS	TC9622-3
SR 3.3.4.1.3-b	C71-N005B	G13.18.6.3-011	BARKSDALE CNTRL/DIV TRANS	TC9622-3
SR 3.3.4.1.3-b	C71-N005C	G13.18.6.3-011	BARKSDALE CNTRL/DIV TRANS	TC9622-3
SR 3.3.4.1.3-b	C71-N005D	G13.18.6.3-011	BARKSDALE CNTRL/DIV TRANS	TC9622-3
SR 3.3.4.1.3-b	C71-N652A	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P216026
SR 3.3.4.1.3-b	C71-N652B	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P216026
SR 3.3.4.1.3-b	C71-N652C	G13.18.6.3-015	ROSEMOUNT	164C5150P216026
SR 3.3.4.1.3-b	C71-N652D	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P216026
SR 3.3.4.1.3-b	C71-N052A	G13.18.6.3-021	ROSEMOUNT	1152GP9N22T0280 PB
SR 3.3.4.1.3-b	C71-N052B	G13.18.6.3-021	ROSEMOUNT	1152GP9N22T0280 PB
SR 3.3.4.1.3-b	C71-N052C	G13.18.6.3-021	ROSEMOUNT	1153GB9RBN0037
SR 3.3.4.1.3-b	C71-N052D	G13.18.6.3-021	ROSEMOUNT	1152GP9E22T0280 PB
SR 3.3.4.1.5-a	C71-N652A	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P216026
SR 3.3.4.1.5-a	C71-N652B	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P216026
SR 3.3.4.1.5-a	C71-N652C	G13.18.6.3-015	ROSEMOUNT	164C5150P216026
SR 3.3.4.1.5-a	C71-N652D	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P216026
SR 3.3.4.1.5-a	C71-N052A	G13.18.6.3-021	ROSEMOUNT	1152GP9N22T0280 PB
SR 3.3.4.1.5-a	C71-N052B	G13.18.6.3-021	ROSEMOUNT	1152GP9N22T0280 PB
SR 3.3.4.1.5-a	C71-N052C	G13.18.6.3-021	ROSEMOUNT	1153GB9RBN0037
SR 3.3.4.1.5-a	C71-N052D	G13.18.6.3-021	ROSEMOUNT	1152GP9E22T0280 PB
SR 3.3.4.1.5-b	C71-N652A	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P216026
SR 3.3.4.1.5-b	C71-N652B	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P216026
SR 3.3.4.1.5-b	C71-N652C	G13.18.6.3-015	ROSEMOUNT	164C5150P216026

SR 3.3.4.1.5-b	C71-N652D	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P216026
SR 3.3.4.1.5-b	C71-N052A	G13.18.6.3-021	ROSEMOUNT	1152GP9N22T0280 PB
SR 3.3.4.1.5-b	C71-N052B	G13.18.6.3-021	ROSEMOUNT	1152GP9N22T0280 PB
SR 3.3.4.1.5-b	C71-N052C	G13.18.6.3-021	ROSEMOUNT	1153GB9RBN0037
SR 3.3.4.1.5-b	C71-N052D	G13.18.6.3-021	ROSEMOUNT	1152GP9E22T0280 PB
SR 3.3.4.2.4-a	B21-N699A	G13.18.6.3-010	BAILEY CONTROLS	745110AAAE1
SR 3.3.4.2.4-a	B21-N699B	G13.18.6.3-010	BAILEY CONTROLS	745110AAAE1
SR 3.3.4.2.4-a	B21-N699E	G13.18.6.3-010	BAILEY CONTROLS	745
SR 3.3.4.2.4-a	B21-N699F	G13.18.6.3-010	BAILEY CONTROLS	745110AAAE1
SR 3.3.4.2.4-a	B21-N099A	G13.18.6.3-018	ROSEMOUNT	1152DP5E22T0280 PB
SR 3.3.4.2.4-a	B21-N099B	G13.18.6.3-018	ROSEMOUNT	1152DP5E22T0280 PB
SR 3.3.4.2.4-a	B21-N099E	G13.18.6.3-018	ROSEMOUNT	1152DP5E22T0280 PB
SR 3.3.4.2.4-a	B21-N099F	G13.18.6.3-018	ROSEMOUNT	1152DP5E22T0280 PB
SR 3.3.4.2.4-b	B21-N658A	G13.18.6.3-010	BAILEY CONTROLS	745110AAAE
SR 3.3.4.2.4-b	B21-N658B	G13.18.6.3-010	BAILEY CONTROLS	745110AAAE
SR 3.3.4.2.4-b	B21-N658E	G13.18.6.3-010	BAILEY CONTROLS	745110AAAE
SR 3.3.4.2.4-b	B21-N658F	G13.18.6.3-010	BAILEY CONTROLS	745110AAAE
SR 3.3.4.2.4-b	B21-N058A	G13.18.6.3-021	ROSEMOUNT	1152GP9N22T0280 PB
SR 3.3.4.2.4-b	B21-N058B	G13.18.6.3-021	ROSEMOUNT	1152GP9E22T0280 PB
SR 3.3.4.2.4-b	B21-N058E	G13.18.6.3-021	ROSEMOUNT	1152GP9E22T0280 PB
SR 3.3.4.2.4-b	B21-N058F	G13.18.6.3-021	ROSEMOUNT	1152GP9E22T0280 PB
SR 3.3.5.1.5-01.a	B21-N692A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-01.a	B21-N692E	G13.18.6.3-015	ROSEMOUNT	710DU0TS
SR 3.3.5.1.5-01.a	B21-N091A	G13.18.6.3-018	ROSEMOUNT	1154DP5RBN0037
SR 3.3.5.1.5-01.a	B21-N091E	G13.18.6.3-018	ROSEMOUNT	1154DP5RBN0037
SR 3.3.5.1.5-01.b	B21-N694A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-01.b	B21-N694E	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-01.b	B21-N094A	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.5.1.5-01.b	B21-N094E	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.5.1.5-01.e	B21-N616E	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60

SR 3.3.5.1.5-01.e	B21-N617A	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.5.1.5-01.e	B21-N618A	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.5.1.5-01.e	B21-N618E	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.5.1.5-01.e	B21-N668A	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB59
SR 3.3.5.1.5-01.e	B21-N668E	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB59
SR 3.3.5.1.5-01.e	B21-N669A	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.5.1.5-01.e	B21-N669E	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.5.1.5-01.e	B21-N670A	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.5.1.5-01.e	B21-N670E	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.5.1.5-01.e	B21-N671A	G13.18.6.3-015	ROSEMOUNT	710DU
SR 3.3.5.1.5-01.e	B21-N671E	G13.18.6.3-015	ROSEMOUNT	710DU
SR 3.3.5.1.5-01.e	B21-N697A	G13.18.6.3-015	ROSEMOUNT	710DU
SR 3.3.5.1.5-01.e	B21-N697E	G13.18.6.3-015	ROSEMOUNT	710DU
SR 3.3.5.1.5-01.e	B21-N698A	G13.18.6.3-015	ROSEMOUNT	710DU
SR 3.3.5.1.5-01.e	B21-N698E	G13.18.6.3-015	ROSEMOUNT	710DU
SR 3.3.5.1.5-01.e	B21-N068A	G13.18.6.3-021	ROSEMOUNT	1152GP9E22T0280 PB
SR 3.3.5.1.5-01.e	B21-N068E	G13.18.6.3-021	ROSEMOUNT	1152GP9E22T0280 PB
SR 3.3.5.1.5-01.f	E21-N651	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P116100
SR 3.3.5.1.5-01.f	E21-N051	G13.18.6.3-017	ROSEMOUNT	1152DP3E22T0280 PB
SR 3.3.5.1.5-01.g	E12-N652A	G13.18.6.3-015	GENERAL ELECTRIC CO	510DU116016A00 5
SR 3.3.5.1.5-01.g	E12-N052A	G13.18.6.3-017	ROSEMOUNT	1153DB3N0037
SR 3.3.5.1.5-2.a	B21-N691B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-2.a	B21-N691F	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-2.a	B21-N692B	G13.18.6.3-015	GENERAL ELECTRIC CO	510
SR 3.3.5.1.5-2.a	B21-N692F	G13.18.6.3-015	GENERAL ELECTRIC CO	510
SR 3.3.5.1.5-2.a	B21-LTN091B	G13.18.6.3-018	ROSEMOUNT	1154DP5RBN0037
SR 3.3.5.1.5-2.a	B21-LTN091F	G13.18.6.3-018	ROSEMOUNT	1154DP5RBN0037
SR 3.3.5.1.5-2.b	B21-N694B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-2.b	B21-N694F	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-2.b	B21-N094B	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.5.1.5-2.b	B21-N094F	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.5.1.5-2.e	B21-N616F	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.5.1.5-2.e	B21-N617B	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.5.1.5-2.e	B21-N618B	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.5.1.5-2.e	B21-N618F	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.5.1.5-2.e	B21-N668B	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB59
SR 3.3.5.1.5-2.e	B21-N668F	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB59

SR 3.3.5.1.5-2.e	B21-N669B	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.5.1.5-2.e	B21-N669F	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.5.1.5-2.e	B21-N670B	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.5.1.5-2.e	B21-N670F	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.5.1.5-2.e	B21-N671B	G13.18.6.3-015	ROSEMOUNT	710DU
SR 3.3.5.1.5-2.e	B21-N671F	G13.18.6.3-015	ROSEMOUNT	710DU
SR 3.3.5.1.5-2.e	B21-N697B	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P700000
SR 3.3.5.1.5-2.e	B21-N697F	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P700000
SR 3.3.5.1.5-2.e	B21-N698B	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P700000
SR 3.3.5.1.5-2.e	B21-N698F	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P700000
SR 3.3.5.1.5-2.e	B21-N068B	G13.18.6.3-021	ROSEMOUNT	1152GP9E22T0280 PB
SR 3.3.5.1.5-2.e	B21-N068F	G13.18.6.3-021	ROSEMOUNT	1152GP9E22T0280 PB
SR 3.3.5.1.5-2.f	E12-N652B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-2.f	E12-N652C	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-2.f	E12-N052B	G13.18.6.3-017	ROSEMOUNT	1153DB3RCN0037
SR 3.3.5.1.5-2.f	E12-N052C	G13.18.6.3-017	ROSEMOUNT	1153DB3RCN0037
SR 3.3.5.1.5-3.a	B21-N673C	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-3.a	B21-N674C	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-3.a	B21-N673G	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-3.a	B21-N673L	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-3.a	B21-N673R	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-3.a	B21-N674L	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-3.a	B21-N073G	G13.18.6.3-018	ROSEMOUNT	1154DP5RBN0037
SR 3.3.5.1.5-3.a	B21-N073L	G13.18.6.3-018	ROSEMOUNT	1154DP5RBN0037
SR 3.3.5.1.5-3.a	B21-N073R	G13.18.6.3-018	ROSEMOUNT	1154DP5RBN0037
SR 3.3.5.1.5-3.a	B21-LTN073C	G13.18.6.3-018	ROSEMOUNT	1154DP5RBN0037
SR 3.3.5.1.5-3.b	B21-N667C	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-3.b	B21-N667G	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-3.b	B21-N667L	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-3.b	B21-N667R	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-3.b	B21-N067C	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.5.1.5-3.b	B21-N067G	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.5.1.5-3.b	B21-N067L	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.5.1.5-3.b	B21-N067R	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.5.1.5-3.c	B21-N673C	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-3.c	B21-N674C	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-3.c	B21-N673L	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-3.c	B21-N674L	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-3.c	B21-N073L	G13.18.6.3-018	ROSEMOUNT	1154DP5RBN0037

SR 3.3.5.1.5-3.c	B21-LTN073C	G13.18.6.3-018	ROSEMOUNT	1154DP5RBN0037
SR 3.3.5.1.5-3.d	E22-N654C	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-3.d	E22-N654G	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-3.d	E22-N054C	G13.18.6.3-018	ROSEMOUNT	1152DP5N22T0280 PB
SR 3.3.5.1.5-3.d	E22-N054G	G13.18.6.3-018	ROSEMOUNT	1152DP5N22T0280 PB
SR 3.3.5.1.5-3.e	E22-N655C	G13.18.6.3-015	ROSEMOUNT	164C5150P216026
SR 3.3.5.1.5-3.e	E22-N655G	G13.18.6.3-015	ROSEMOUNT	164C5150P216026
SR 3.3.5.1.5-3.e	E22-N055C	G13.18.6.3-017	ROSEMOUNT	1153GB3PA
SR 3.3.5.1.5-3.e	E22-N055G	G13.18.6.3-017	ROSEMOUNT	1153GB3PA
SR 3.3.5.1.5-3.f	E22-N651	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-3.f	E22-N051	G13.18.6.3-021	ROSEMOUNT	1152GP9E22T0280 PB
SR 3.3.5.1.5-3.g	E22-N656	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-3.g	E22-N056	G13.18.6.3-018	ROSEMOUNT	1154DP4RBN0037
SR 3.3.5.1.5-4.a	B21-N691A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-4.a	B21-N691E	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-4.a	B21-N692A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-4.a	B21-N692E	G13.18.6.3-015	ROSEMOUNT	710DU0TS
SR 3.3.5.1.5-4.a	B21-N091A	G13.18.6.3-018	ROSEMOUNT	1154DP5RBN0037
SR 3.3.5.1.5-4.a	B21-N091E	G13.18.6.3-018	ROSEMOUNT	1154DP5RBN0037
SR 3.3.5.1.5-4.b	B21-N694A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-4.b	B21-N694E	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-4.b	B21-N094A	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.5.1.5-4.b	B21-N094E	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.5.1.5-4.d	B21-N693A	G13.18.6.3-015	ROSEMOUNT	710DU0TS
SR 3.3.5.1.5-4.d	B21-N695A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-4.d	B21-N095A	G13.18.6.3-018	ROSEMOUNT	1152DP4E22T0280 PB
SR 3.3.5.1.5-4.e	E21-N652	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-4.e	E21-N653	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-4.e	E21-N052	G13.18.6.3-020	ROSEMOUNT	1152GP7E22T0280 PB
SR 3.3.5.1.5-4.e	E21-N053	G13.18.6.3-020	ROSEMOUNT	1152GP7N22T0280 PB
SR 3.3.5.1.5-4.f	E12-N655A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-4.f	E12-N656A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-4.f	E12-N055A	G13.18.6.3-020	ROSEMOUNT	1152GP7N22T0280 PB

SR 3.3.5.1.5-4.f	E12-N056A	G13.18.6.3-020	ROSEMOUNT	1152GP7N22T0280 PB
SR 3.3.5.1.5-5.a	B21-N691B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-5.a	B21-N691F	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-5.a	B21-N692B	G13.18.6.3-015	GENERAL ELECTRIC CO	510
SR 3.3.5.1.5-5.a	B21-N692F	G13.18.6.3-015	GENERAL ELECTRIC CO	510
SR 3.3.5.1.5-5.a	B21-LTN091B	G13.18.6.3-018	ROSEMOUNT	1154DP5RBN0037
SR 3.3.5.1.5-5.a	B21-LTN091F	G13.18.6.3-018	ROSEMOUNT	1154DP5RBN0037
SR 3.3.5.1.5-5.b	B21-N694B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-5.b	B21-N694F	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-5.b	B21-N094B	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.5.1.5-5.b	B21-N094F	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.5.1.5-5.d	B21-N693B	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P700000
SR 3.3.5.1.5-5.d	B21-N695B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-5.d	B21-N095B	G13.18.6.3-018	ROSEMOUNT	1152DP4E22T0280 PB
SR 3.3.5.1.5-5.e	E12-N655B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-5.e	E12-N655C	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-5.e	E12-N656B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-5.e	E12-N656C	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.1.5-5.e	E12-N055B	G13.18.6.3-020	ROSEMOUNT	1152GP7N22T0280 PB
SR 3.3.5.1.5-5.e	E12-N055C	G13.18.6.3-020	ROSEMOUNT	1152GP7N22T0280 PB
SR 3.3.5.1.5-5.e	E12-N056B	G13.18.6.3-020	ROSEMOUNT	1152GP7N22T0280 PB
SR 3.3.5.1.5-5.e	E12-N056C	G13.18.6.3-020	ROSEMOUNT	1152GP7N22T0280 PB
SR 3.3.5.2.4-1	B21-N691B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.2.4-1	B21-N691F	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.2.4-1	B21-N692B	G13.18.6.3-015	GENERAL ELECTRIC CO	510
SR 3.3.5.2.4-1	B21-N692F	G13.18.6.3-015	GENERAL ELECTRIC CO	510
SR 3.3.5.2.4-1	B21-N691A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.2.4-1	B21-N691E	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.2.4-1	B21-N692A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.2.4-1	B21-N692E	G13.18.6.3-015	ROSEMOUNT	710DU0TS
SR 3.3.5.2.4-1	B21-N091A	G13.18.6.3-018	ROSEMOUNT	1154DP5RBN0037
SR 3.3.5.2.4-1	B21-N091E	G13.18.6.3-018	ROSEMOUNT	1154DP5RBN0037
SR 3.3.5.2.4-1	B21-LTN091B	G13.18.6.3-018	ROSEMOUNT	1154DP5RBN0037
SR 3.3.5.2.4-1	B21-LTN091F	G13.18.6.3-018	ROSEMOUNT	1154DP5RBN0037
SR 3.3.5.2.4-2	B21-N693A	G13.18.6.3-015	ROSEMOUNT	710DU0TS

SR 3.3.5.2.4-2	B21-N693B	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P700000
SR 3.3.5.2.4-2	B21-N695A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.2.4-2	B21-N695B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.2.4-2	B21-N095A	G13.18.6.3-018	ROSEMOUNT	1152DP4E22T0280 PB
SR 3.3.5.2.4-2	B21-N095B	G13.18.6.3-018	ROSEMOUNT	1152DP4E22T0280 PB
SR 3.3.5.2.4-3	E51-N635A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.2.4-3	E51-N635E	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.2.4-3	E51-N035A	G13.18.6.3-018	ROSEMOUNT	1153DB5PC
SR 3.3.5.2.4-3	E51-N035E	G13.18.6.3-018	ROSEMOUNT	1152DP5E22T0280 PB
SR 3.3.5.2.4-4	E51-N636A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.2.4-4	E51-N636E	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.5.2.4-4	E51-N036A	G13.18.6.3-017	ROSEMOUNT	1153DB3PA
SR 3.3.5.2.4-4	E51-N036E	G13.18.6.3-017	ROSEMOUNT	1153DB3PA
SR 3.3.6.1.5-1.a	B21-N681A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-1.a	B21-N681D	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-1.a	B21-N682A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-1.a	B21-N682D	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-1.a	B21-N681B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-1.a	B21-N681C	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-1.a	B21-N682B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-1.a	B21-N682C	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-1.a	B21-N081B	G13.18.6.3-018	ROSEMOUNT	1152DP5E22T0280 PB
SR 3.3.6.1.5-1.a	B21-N081C	G13.18.6.3-018	ROSEMOUNT	1152DP5E22T0280 PB
SR 3.3.6.1.5-1.a	B21-LTN081A	G13.18.6.3-018	ROSEMOUNT	1152DP5E22T0280 PB
SR 3.3.6.1.5-1.a	B21-LTN081D	G13.18.6.3-018	ROSEMOUNT	1152DP5E22T0280 PB
SR 3.3.6.1.5-1.b	B21-N676A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-1.b	B21-N676C	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-1.b	B21-N676B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-1.b	B21-N676D	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-1.b	B21-N076B	G13.18.6.3-021	ROSEMOUNT	1152GP9E22T0280 PB
SR 3.3.6.1.5-1.b	B21-N076D	G13.18.6.3-021	ROSEMOUNT	1152GP9E22T0280 PB

SR 3.3.6.1.5-1.b	B21-PTN076A	G13.18.6.3-021	ROSEMOUNT	1152GP9E22T0280 PB
SR 3.3.6.1.5-1.b	B21-PTN076C	G13.18.6.3-021	ROSEMOUNT	1152GP9E22T0280 PB
SR 3.3.6.1.5-1.c	E31-N686C	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P223522
SR 3.3.6.1.5-1.c	E31-N687D	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P223522
SR 3.3.6.1.5-1.c	E31-N688D	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P223522
SR 3.3.6.1.5-1.c	E31-N686A	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P223522
SR 3.3.6.1.5-1.c	E31-N686B	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P223522
SR 3.3.6.1.5-1.c	E31-N686D	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P223522
SR 3.3.6.1.5-1.c	E31-N687A	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P223522
SR 3.3.6.1.5-1.c	E31-N687B	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P223522
SR 3.3.6.1.5-1.c	E31-N687C	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P223522
SR 3.3.6.1.5-1.c	E31-N688A	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P223522
SR 3.3.6.1.5-1.c	E31-N688B	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P223522
SR 3.3.6.1.5-1.c	E31-N688C	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P223522
SR 3.3.6.1.5-1.c	E31-N689A	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P223522
SR 3.3.6.1.5-1.c	E31-N689B	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P223522
SR 3.3.6.1.5-1.c	E31-N689C	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P223522
SR 3.3.6.1.5-1.c	E31-N689D	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P223522
SR 3.3.6.1.5-1.c	E31-N086A	G13.18.6.3-023	ROSEMOUNT	1153DB7N0037
SR 3.3.6.1.5-1.c	E31-N086B	G13.18.6.3-023	ROSEMOUNT	1153DB7N0037
SR 3.3.6.1.5-1.c	E31-N086D	G13.18.6.3-023	ROSEMOUNT	1152DP7E22T0280 PB
SR 3.3.6.1.5-1.c	E31-N087A	G13.18.6.3-023	ROSEMOUNT	1152DP7E22T0280 PB
SR 3.3.6.1.5-1.c	E31-N087B	G13.18.6.3-023	ROSEMOUNT	1152DP7E22T0280 PB
SR 3.3.6.1.5-1.c	E31-N087C	G13.18.6.3-023	ROSEMOUNT	1152DP7E22T0280 PB
SR 3.3.6.1.5-1.c	E31-N088A	G13.18.6.3-023	ROSEMOUNT	1153DB7PA
SR 3.3.6.1.5-1.c	E31-N088B	G13.18.6.3-023	ROSEMOUNT	1152DP7E22T0280 PB
SR 3.3.6.1.5-1.c	E31-N088C	G13.18.6.3-023	ROSEMOUNT	1152DP7E22T0280 PB
SR 3.3.6.1.5-1.c	E31-N089A	G13.18.6.3-023	ROSEMOUNT	1152DP7E22T0280 PB
SR 3.3.6.1.5-1.c	E31-N089B	G13.18.6.3-023	ROSEMOUNT	1152DP7E22T0280 PB
SR 3.3.6.1.5-1.c	E31-N089C	G13.18.6.3-023	ROSEMOUNT	1152DP7E22T0280 PB

SR 3.3.6.1.5-1.c	E31-N089D	G13.18.6.3-023	ROSEMOUNT	1152DP7E22T0280 PB
SR 3.3.6.1.5-1.c	E31-PDTN086C	G13.18.6.3-023	ROSEMOUNT	1152DP7E22T0280 PB
SR 3.3.6.1.5-1.c	E31-PDTN087D	G13.18.6.3-023	ROSEMOUNT	1152DP7E22T0280 PB
SR 3.3.6.1.5-1.c	E31-PDTN088D	G13.18.6.3-023	ROSEMOUNT	1152DP7E22T0280 PB
SR 3.3.6.1.5-1.d	B21-N675A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-1.d	B21-N675B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-1.d	B21-N675C	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-1.d	B21-N675D	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-1.d	B21-N075B	G13.18.6.3-019	ROSEMOUNT	1152AP5N22T0280 PB
SR 3.3.6.1.5-1.d	B21-N075C	G13.18.6.3-019	ROSEMOUNT	1152AP5E22T0280 PB
SR 3.3.6.1.5-1.d	B21-N075D	G13.18.6.3-019	ROSEMOUNT	1152AP5E22T0280 PB
SR 3.3.6.1.5-1.d	B21-N075A	G13.18.6.3-019	ROSEMOUNT	1152AP5E22T0280 PB
SR 3.3.6.1.5-2.a	B21-N673C	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-2.a	B21-N674C	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-2.a	B21-N681A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-2.a	B21-N681D	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-2.a	B21-N682A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-2.a	B21-N682D	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-2.a	B21-N673G	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-2.a	B21-N673L	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-2.a	B21-N673R	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-2.a	B21-N674L	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-2.a	B21-N681B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-2.a	B21-N681C	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-2.a	B21-N682B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-2.a	B21-N682C	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-2.a	B21-N073G	G13.18.6.3-018	ROSEMOUNT	1154DP5RBN0037
SR 3.3.6.1.5-2.a	B21-N073L	G13.18.6.3-018	ROSEMOUNT	1154DP5RBN0037
SR 3.3.6.1.5-2.a	B21-N073R	G13.18.6.3-018	ROSEMOUNT	1154DP5RBN0037
SR 3.3.6.1.5-2.a	B21-N081B	G13.18.6.3-018	ROSEMOUNT	1152DP5E22T0280 PB
SR 3.3.6.1.5-2.a	B21-N081C	G13.18.6.3-018	ROSEMOUNT	1152DP5E22T0280 PB

SR 3.3.6.1.5-2.a	B21-LTN081A	G13.18.6.3-018	ROSEMOUNT	1152DP5E22T0280 PB
SR 3.3.6.1.5-2.a	B21-LTN081D	G13.18.6.3-018	ROSEMOUNT	1152DP5E22T0280 PB
SR 3.3.6.1.5-2.a	B21-LTN073C	G13.18.6.3-018	ROSEMOUNT	1154DP5RBN0037
SR 3.3.6.1.5-2.b	B21-N667C	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-2.b	B21-N667G	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-2.b	B21-N667L	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-2.b	B21-N667R	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-2.b	B21-N694A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-2.b	B21-N694B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-2.b	C71-N650A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-2.b	C71-N650B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-2.b	C71-N650C	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-2.b	C71-N650D	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-2.b	C71-N651	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-2.b	C71-N653	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-2.b	B21-N067C	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.6.1.5-2.b	B21-N067G	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.6.1.5-2.b	B21-N067L	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.6.1.5-2.b	B21-N067R	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.6.1.5-2.b	B21-N094A	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.6.1.5-2.b	B21-N094B	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.6.1.5-2.b	C71-N050A	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.6.1.5-2.b	C71-N050B	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.6.1.5-2.b	C71-N050C	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.6.1.5-2.b	C71-N050D	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.6.1.5-3.a	E31-N683A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-3.a	E31-N690A	G13.18.6.3-015	ROSEMOUNT	710DU0TS
SR 3.3.6.1.5-3.a	E31-N683B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-3.a	E31-N690B	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P700000
SR 3.3.6.1.5-3.a	E31-N083B	G13.18.6.3-023	ROSEMOUNT	1153DB5RBN0037
SR 3.3.6.1.5-3.a	E31-PDTN083A	G13.18.6.3-023	ROSEMOUNT	1153DB5PCN0016
SR 3.3.6.1.5-3.c	E31-N685A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-3.c	E31-N685B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-3.c	E31-PTN085A	G13.18.6.3-020	ROSEMOUNT	1152GP7N22T0280 PB
SR 3.3.6.1.5-3.c	E31-PTN085B	G13.18.6.3-020	ROSEMOUNT	1152GP7N22T0280 PB
SR 3.3.6.1.5-3.d	E51-N655A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-3.d	E51-N655B	G13.18.6.3-015	ROSEMOUNT	510DU

SR 3.3.6.1.5-3.d	E51-N655E	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-3.d	E51-N655F	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-3.d	E51-N055A	G13.18.6.3-016	ROSEMOUNT	1153GB6PB
SR 3.3.6.1.5-3.d	E51-N055B	G13.18.6.3-016	ROSEMOUNT	1153GB6RBN0037
SR 3.3.6.1.5-3.d	E51-N055E	G13.18.6.3-016	ROSEMOUNT	1153GB6PB
SR 3.3.6.1.5-3.d	E51-N055F	G13.18.6.3-016	ROSEMOUNT	1153GB6RBN0037
SR 3.3.6.1.5-3.i	E31-N684A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-3.i	E31-N684B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-3.i	E31-N691A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-3.i	E31-N691B	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P700000
SR 3.3.6.1.5-3.i	E31-PDTN084A	G13.18.6.3-018	ROSEMOUNT	1152DP5E22T0280 PB
SR 3.3.6.1.5-3.i	E31-PDTN084B	G13.18.6.3-018	ROSEMOUNT	1152DP5N22T0280 PB
SR 3.3.6.1.5-3.j	B21-N694A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-3.j	B21-N694B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-3.j	B21-N094A	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.6.1.5-3.j	B21-N094B	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.6.1.5-4.a	E31-N609A	G13.18.6.3-010	BAILEY METER	745110AAAE1
SR 3.3.6.1.5-4.a	E31-N609B	G13.18.6.3-010	BAILEY METER	745110AAAE1
SR 3.3.6.1.5-4.a	E31-FTN077A	G13.18.6.3-018	ROSEMOUNT	1153DB5PCN0037
SR 3.3.6.1.5-4.a	E31-FTN077B	G13.18.6.3-018	ROSEMOUNT	1153DB5PCN0037
SR 3.3.6.1.5-4.a	E31-FTN075A	G13.18.6.3-023	ROSEMOUNT INC	1153DB5PC
SR 3.3.6.1.5-4.a	E31-FTN075B	G13.18.6.3-023	ROSEMOUNT	1153DB5PCN0037
SR 3.3.6.1.5-4.a	E31-FTN076A	G13.18.6.3-023	ROSEMOUNT	1152DP5E22T0280 PB
SR 3.3.6.1.5-4.a	E31-FTN076B	G13.18.6.3-023	ROSEMOUNT	1152DP5E22T0280 PB
SR 3.3.6.1.5-4.a	E31-K602A	G13.18.6.3-024	BAILEY METER	750010AAAE1
SR 3.3.6.1.5-4.a	E31-K602B	G13.18.6.3-024	BAILEY METER	750010AAAE1
SR 3.3.6.1.5-4.a	E31-K603A	G13.18.6.3-024	BAILEY METER	750010AAAE1
SR 3.3.6.1.5-4.a	E31-K603B	G13.18.6.3-024	BAILEY METER	750010AAAE1
SR 3.3.6.1.5-4.a	E31-K604A	G13.18.6.3-024	BAILEY METER	752410AAAE1
SR 3.3.6.1.5-4.a	E31-K604B	G13.18.6.3-024	BAILEY METER	752410AAAE1
SR 3.3.6.1.5-4.a	E31-K605A	G13.18.6.3-024	BAILEY METER	750010AAAE1
SR 3.3.6.1.5-4.a	E31-K605B	G13.18.6.3-024	BAILEY METER	750010AAAE1
SR 3.3.6.1.5-4.i	B21-N681A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-4.i	B21-N681D	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-4.i	B21-N682A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-4.i	B21-N682D	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-4.i	B21-N681B	G13.18.6.3-015	ROSEMOUNT	510DU

SR 3.3.6.1.5-4.i	B21-N681C	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-4.i	B21-N682B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-4.i	B21-N682C	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-4.i	B21-N081B	G13.18.6.3-018	ROSEMOUNT	1152DP5E22T0280 PB
SR 3.3.6.1.5-4.i	B21-N081C	G13.18.6.3-018	ROSEMOUNT	1152DP5E22T0280 PB
SR 3.3.6.1.5-4.i	B21-LTN081A	G13.18.6.3-018	ROSEMOUNT	1152DP5E22T0280 PB
SR 3.3.6.1.5-4.i	B21-LTN081D	G13.18.6.3-018	ROSEMOUNT	1152DP5E22T0280 PB
SR 3.3.6.1.5-5.b	B21-N680A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-5.b	B21-N680B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-5.b	B21-N680C	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-5.b	B21-N680D	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-5.b	B21-N683A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-5.b	B21-N683B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-5.b	B21-N683C	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-5.b	B21-N683D	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-5.b	B21-N080A	G13.18.6.3-018	ROSEMOUNT	1152DP4E22T0280 PB
SR 3.3.6.1.5-5.b	B21-N080B	G13.18.6.3-018	ROSEMOUNT	1152DP4E22T0280 PB
SR 3.3.6.1.5-5.b	B21-N080C	G13.18.6.3-018	ROSEMOUNT	1152DP4E22T0280 PB
SR 3.3.6.1.5-5.b	B21-N080D	G13.18.6.3-018	ROSEMOUNT	1153DB4N0037
SR 3.3.6.1.5-5.c	B21-N691B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-5.c	B21-N691F	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-5.c	B21-N692B	G13.18.6.3-015	GENERAL ELECTRIC CO	510
SR 3.3.6.1.5-5.c	B21-N692F	G13.18.6.3-015	GENERAL ELECTRIC CO	510
SR 3.3.6.1.5-5.c	B21-N691A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-5.c	B21-N691E	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-5.c	B21-N692A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-5.c	B21-N692E	G13.18.6.3-015	ROSEMOUNT	710DU0TS
SR 3.3.6.1.5-5.c	B21-N091A	G13.18.6.3-018	ROSEMOUNT	1154DP5RBN0037
SR 3.3.6.1.5-5.c	B21-N091E	G13.18.6.3-018	ROSEMOUNT	1154DP5RBN0037
SR 3.3.6.1.5-5.c	B21-LTN091B	G13.18.6.3-018	ROSEMOUNT	1154DP5RBN0037
SR 3.3.6.1.5-5.c	B21-LTN091F	G13.18.6.3-018	ROSEMOUNT	1154DP5RBN0037
SR 3.3.6.1.5-5.d	B21-N678A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-5.d	B21-N678B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-5.d	B21-N678C	G13.18.6.3-015	ROSEMOUNT	510DU

SR 3.3.6.1.5-5.d	B21-N678D	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-5.d	B21-N679A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-5.d	B21-N679B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-5.d	B21-N679C	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-5.d	B21-N679D	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-5.d	B21-N078A	G13.18.6.3-021	ROSEMOUNT	1152GP9E22T0280 PB
SR 3.3.6.1.5-5.d	B21-N078B	G13.18.6.3-021	ROSEMOUNT	1152GP9E22T0280 PB
SR 3.3.6.1.5-5.d	B21-N078C	G13.18.6.3-021	ROSEMOUNT	1152GP9E22T0280 PB
SR 3.3.6.1.5-5.d	B21-N078D	G13.18.6.3-021	ROSEMOUNT	1152GP9E22T0280 PB
SR 3.3.6.1.5-5.e	B21-N694A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-5.e	B21-N694B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-5.e	B21-N694E	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-5.e	B21-N694F	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-5.e	C71-N650A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-5.e	C71-N650B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-5.e	C71-N650C	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-5.e	C71-N650D	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-5.e	C71-N651	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-5.e	C71-N653	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.1.5-5.e	B21-N094A	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.6.1.5-5.e	B21-N094B	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.6.1.5-5.e	B21-N094E	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.6.1.5-5.e	B21-N094F	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.6.1.5-5.e	C71-N050A	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.6.1.5-5.e	C71-N050B	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.6.1.5-5.e	C71-N050C	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.6.1.5-5.e	C71-N050D	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.6.2.4-1	B21-N681A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.2.4-1	B21-N681D	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.2.4-1	B21-N682A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.2.4-1	B21-N682D	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.2.4-1	B21-N681B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.2.4-1	B21-N681C	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.2.4-1	B21-N682B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.2.4-1	B21-N682C	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.2.4-1	B21-N081B	G13.18.6.3-018	ROSEMOUNT	1152DP5E22T0280 PB

SR 3.3.6.2.4-1	B21-N081C	G13.18.6.3-018	ROSEMOUNT	1152DP5E22T0280 PB
SR 3.3.6.2.4-1	B21-LTN081A	G13.18.6.3-018	ROSEMOUNT	1152DP5E22T0280 PB
SR 3.3.6.2.4-1	B21-LTN081D	G13.18.6.3-018	ROSEMOUNT	1152DP5E22T0280 PB
SR 3.3.6.2.4-2	C71-N650A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.2.4-2	C71-N650B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.2.4-2	C71-N650C	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.2.4-2	C71-N650D	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.2.4-2	C71-N651	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.2.4-2	C71-N653	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.2.4-2	C71-N050A	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.6.2.4-2	C71-N050B	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.6.2.4-2	C71-N050C	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.6.2.4-2	C71-N050D	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.6.3.4-2	HVR-ESX60A	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P700000
SR 3.3.6.3.4-2	HVR-ESX60B	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P700000
SR 3.3.6.3.4-2	HVR-ESX60C	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P244533
SR 3.3.6.3.4-2	HVR-ESX60D	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P244533
SR 3.3.6.3.4-2	HVR-ESX60E	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P244533
SR 3.3.6.3.4-2	HVR-ESX60F	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P244533
SR 3.3.6.3.4-2	HVR-ESY60A	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P700000
SR 3.3.6.3.4-2	HVR-ESY60B	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P700000
SR 3.3.6.3.4-2	HVR-ESY60C	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P700000
SR 3.3.6.3.4-2	HVR-ESY60D	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P700000
SR 3.3.6.3.4-2	HVR-ESY60E	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P700000
SR 3.3.6.3.4-2	HVR-ESY60F	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P244533
SR 3.3.6.3.4-2	HVR-ESZ60A	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P244533
SR 3.3.6.3.4-2	HVR-ESZ60B	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P244533
SR 3.3.6.3.4-2	HVR-PDT60A	G13.18.6.3-017	ROSEMOUNT	1153DB3PA
SR 3.3.6.3.4-2	HVR-PDT60B	G13.18.6.3-017	ROSEMOUNT	1153DB3PA
SR 3.3.6.3.4-2	HVR-PDT60C	G13.18.6.3-017	ROSEMOUNT	1153DB3PA
SR 3.3.6.3.4-2	HVR-PDT60D	G13.18.6.3-017	ROSEMOUNT	1153DB3PA
SR 3.3.6.3.4-2	HVR-PDT60E	G13.18.6.3-017	ROSEMOUNT	1153DB3PA
SR 3.3.6.3.4-2	HVR-PDT60F	G13.18.6.3-017	ROSEMOUNT	1153DB3PA
SR 3.3.6.3.4-3	B21-N691B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.3.4-3	B21-N691F	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.3.4-3	B21-N692B	G13.18.6.3-015	GENERAL ELECTRIC CO	510
SR 3.3.6.3.4-3	B21-N692F	G13.18.6.3-015	GENERAL ELECTRIC CO	510
SR 3.3.6.3.4-3	B21-N691A	G13.18.6.3-015	ROSEMOUNT	510DU

SR 3.3.6.3.4-3	B21-N691E	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.3.4-3	B21-N692A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.3.4-3	B21-N692E	G13.18.6.3-015	ROSEMOUNT	710DU0TS
SR 3.3.6.3.4-3	B21-N091A	G13.18.6.3-018	ROSEMOUNT	1154DP5RBN0037
SR 3.3.6.3.4-3	B21-N091E	G13.18.6.3-018	ROSEMOUNT	1154DP5RBN0037
SR 3.3.6.3.4-3	B21-LTN091B	G13.18.6.3-018	ROSEMOUNT	1154DP5RBN0037
SR 3.3.6.3.4-3	B21-LTN091F	G13.18.6.3-018	ROSEMOUNT	1154DP5RBN0037
SR 3.3.6.3.4-4	HVR-A02-62A	G13.18.6.3-014	AMERACE CORP (Agastat)	ETR14D3NC200400 3
SR 3.3.6.3.4-4	HVR-B02-62A	G13.18.6.3-014	AMERACE CORP (Agastat)	ETR14D3NC200400 3
SR 3.3.6.3.4-1	B21-N694A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.3.4-1	B21-N694B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.3.4-1	B21-N694E	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.3.4-1	B21-N694F	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.6.3.4-1	B21-N094A	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.6.3.4-1	B21-N094B	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.6.3.4-1	B21-N094E	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.6.3.4-1	B21-N094F	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.6.4.3-a	B21-N616E	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.6.4.3-a	B21-N616F	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.6.4.3-a	B21-N617A	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.6.4.3-a	B21-N617B	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.6.4.3-a	B21-N618A	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.6.4.3-a	B21-N618B	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.6.4.3-a	B21-N618E	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.6.4.3-a	B21-N618F	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.6.4.3-a	B21-N668A	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB59
SR 3.3.6.4.3-a	B21-N668B	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB59
SR 3.3.6.4.3-a	B21-N668E	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB59
SR 3.3.6.4.3-a	B21-N668F	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB59
SR 3.3.6.4.3-a	B21-N669A	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.6.4.3-a	B21-N669B	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.6.4.3-a	B21-N669E	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.6.4.3-a	B21-N669F	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.6.4.3-a	B21-N670A	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.6.4.3-a	B21-N670B	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.6.4.3-a	B21-N670E	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.6.4.3-a	B21-N670F	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.6.4.3-a	B21-N671A	G13.18.6.3-015	ROSEMOUNT	710DU
SR 3.3.6.4.3-a	B21-N671B	G13.18.6.3-015	ROSEMOUNT	710DU

SR 3.3.6.4.3-a	B21-N671E	G13.18.6.3-015	ROSEMOUNT	710DU
SR 3.3.6.4.3-a	B21-N671F	G13.18.6.3-015	ROSEMOUNT	710DU
SR 3.3.6.4.3-a	B21-N697A	G13.18.6.3-015	ROSEMOUNT	710DU
SR 3.3.6.4.3-a	B21-N697B	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P700000
SR 3.3.6.4.3-a	B21-N697E	G13.18.6.3-015	ROSEMOUNT	710DU
SR 3.3.6.4.3-a	B21-N697F	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P700000
SR 3.3.6.4.3-a	B21-N698A	G13.18.6.3-015	ROSEMOUNT	710DU
SR 3.3.6.4.3-a	B21-N698B	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P700000
SR 3.3.6.4.3-a	B21-N698E	G13.18.6.3-015	ROSEMOUNT	710DU
SR 3.3.6.4.3-a	B21-N698F	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P700000
SR 3.3.6.4.3-a	B21-N068A	G13.18.6.3-021	ROSEMOUNT	1152GP9E22T0280 PB
SR 3.3.6.4.3-a	B21-N068B	G13.18.6.3-021	ROSEMOUNT	1152GP9E22T0280 PB
SR 3.3.6.4.3-a	B21-N068E	G13.18.6.3-021	ROSEMOUNT	1152GP9E22T0280 PB
SR 3.3.6.4.3-a	B21-N068F	G13.18.6.3-021	ROSEMOUNT	1152GP9E22T0280 PB
SR 3.3.6.4.3-b	B21-N616E	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.6.4.3-b	B21-N616F	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.6.4.3-b	B21-N617A	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.6.4.3-b	B21-N617B	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.6.4.3-b	B21-N618A	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.6.4.3-b	B21-N618B	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.6.4.3-b	B21-N618E	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.6.4.3-b	B21-N618F	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.6.4.3-b	B21-N668A	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB59
SR 3.3.6.4.3-b	B21-N668B	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB59
SR 3.3.6.4.3-b	B21-N668E	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB59
SR 3.3.6.4.3-b	B21-N668F	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB59
SR 3.3.6.4.3-b	B21-N669A	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.6.4.3-b	B21-N669B	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.6.4.3-b	B21-N669E	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.6.4.3-b	B21-N669F	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.6.4.3-b	B21-N670A	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.6.4.3-b	B21-N670B	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.6.4.3-b	B21-N670E	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.6.4.3-b	B21-N670F	G13.18.6.3-015	GENERAL ELECTRIC CO	304A1658PB60
SR 3.3.6.4.3-b	B21-N671A	G13.18.6.3-015	ROSEMOUNT	710DU
SR 3.3.6.4.3-b	B21-N671B	G13.18.6.3-015	ROSEMOUNT	710DU
SR 3.3.6.4.3-b	B21-N671E	G13.18.6.3-015	ROSEMOUNT	710DU

SR 3.3.6.4.3-b	B21-N671F	G13.18.6.3-015	ROSEMOUNT	710DU
SR 3.3.6.4.3-b	B21-N697A	G13.18.6.3-015	ROSEMOUNT	710DU
SR 3.3.6.4.3-b	B21-N697B	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P700000
SR 3.3.6.4.3-b	B21-N697E	G13.18.6.3-015	ROSEMOUNT	710DU
SR 3.3.6.4.3-b	B21-N697F	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P700000
SR 3.3.6.4.3-b	B21-N698A	G13.18.6.3-015	ROSEMOUNT	710DU
SR 3.3.6.4.3-b	B21-N698B	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P700000
SR 3.3.6.4.3-b	B21-N698E	G13.18.6.3-015	ROSEMOUNT	710DU
SR 3.3.6.4.3-b	B21-N698F	G13.18.6.3-015	GENERAL ELECTRIC CO	164C5150P700000
SR 3.3.6.4.3-b	B21-N068A	G13.18.6.3-021	ROSEMOUNT	1152GP9E22T0280 PB
SR 3.3.6.4.3-b	B21-N068B	G13.18.6.3-021	ROSEMOUNT	1152GP9E22T0280 PB
SR 3.3.6.4.3-b	B21-N068E	G13.18.6.3-021	ROSEMOUNT	1152GP9E22T0280 PB
SR 3.3.6.4.3-b	B21-N068F	G13.18.6.3-021	ROSEMOUNT	1152GP9E22T0280 PB
SR 3.3.7.1.4-1	B21-LTN081A	G13.18.6.3-018	ROSEMOUNT	1152DP5E22T0280 PB
SR 3.3.7.1.4-1	B21-LTN081D	G13.18.6.3-018	ROSEMOUNT	1152DP5E22T0280 PB
SR 3.3.7.1.4-2	C71-N650A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.7.1.4-2	C71-N650B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.7.1.4-2	C71-N650C	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.7.1.4-2	C71-N650D	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.7.1.4-2	C71-N651	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.7.1.4-2	C71-N653	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.7.1.4-2	C71-N050A	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.7.1.4-2	C71-N050B	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.7.1.4-2	C71-N050C	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.7.1.4-2	C71-N050D	G13.18.6.3-023	ROSEMOUNT	1154DP4RB
SR 3.3.7.1.4-1	B21-N681A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.7.1.4-1	B21-N681D	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.7.1.4-1	B21-N682A	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.7.1.4-1	B21-N682D	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.7.1.4-1	B21-N681B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.7.1.4-1	B21-N681C	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.7.1.4-1	B21-N682B	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.7.1.4-1	B21-N682C	G13.18.6.3-015	ROSEMOUNT	510DU
SR 3.3.7.1.4-1	B21-N081B	G13.18.6.3-018	ROSEMOUNT	1152DP5E22T0280 PB

SR 3.3.7.1.4-1	B21-N081C	G13.18.6.3-018	ROSEMOUNT	1152DP5E22T0280 PB
SR 3.3.8.1.3-1.a	ENS-SWG1A-27-1A	G13.18.6.3-006	ASEA BROWN BOVERI	ITE-27H
SR 3.3.8.1.3-1.a	ENS-SWG1A-27-1B	G13.18.6.3-006	ASEA BROWN BOVERI	ITE-27H
SR 3.3.8.1.3-1.a	ENS-SWG1A-27-1C	G13.18.6.3-006	ASEA BROWN BOVERI	ITE-27H
SR 3.3.8.1.3-1.a	ENS-SWG1B-27-1A	G13.18.6.3-006	ASEA BROWN BOVERI	ITE-27H
SR 3.3.8.1.3-1.a	ENS-SWG1B-27-1B	G13.18.6.3-006	ASEA BROWN BOVERI	ITE-27H
SR 3.3.8.1.3-1.a	ENS-SWG1B-27-1C	G13.18.6.3-006	ASEA BROWN BOVERI	ITE-27H
SR 3.3.8.1.3-1.b	ENS-SWG1A-62-1	G13.18.6.3-009	ASEA BROWN BOVERI	ITE-62K
SR 3.3.8.1.3-1.b	ENS-SWG1B-62-1	G13.18.6.3-009	ASEA BROWN BOVERI	ITE-62K
SR 3.3.8.1.3-1.c	ENS-SWG1A-27/62-2A	G13.18.6.3-007	ASEA BROWN BOVERI	ITE-27N
SR 3.3.8.1.3-1.c	ENS-SWG1A-27/62-2B	G13.18.6.3-007	ASEA BROWN BOVERI	ITE-27N
SR 3.3.8.1.3-1.c	ENS-SWG1A-27/62-2C	G13.18.6.3-007	ASEA BROWN BOVERI	ITE-27N
SR 3.3.8.1.3-1.c	ENS-SWG1B-27/62-2A	G13.18.6.3-007	ASEA BROWN BOVERI	ITE-27N
SR 3.3.8.1.3-1.c	ENS-SWG1B-27/62-2B	G13.18.6.3-007	ASEA BROWN BOVERI	ITE-27N
SR 3.3.8.1.3-1.c	ENS-SWG1B-27/62-2C	G13.18.6.3-007	ASEA BROWN BOVERI	ITE-27N
SR 3.3.8.1.3-1.c	ENS-SWG1A-27/62-2A	G13.18.6.3-008	ASEA BROWN BOVERI	ITE-27N
SR 3.3.8.1.3-1.c	ENS-SWG1A-27/62-2B	G13.18.6.3-008	ASEA BROWN BOVERI	ITE-27N
SR 3.3.8.1.3-1.c	ENS-SWG1A-27/62-2C	G13.18.6.3-008	ASEA BROWN BOVERI	ITE-27N
SR 3.3.8.1.3-1.c	ENS-SWG1B-27/62-2A	G13.18.6.3-008	ASEA BROWN BOVERI	ITE-27N
SR 3.3.8.1.3-1.c	ENS-SWG1B-27/62-2B	G13.18.6.3-008	ASEA BROWN BOVERI	ITE-27N
SR 3.3.8.1.3-1.c	ENS-SWG1B-27/62-2C	G13.18.6.3-008	ASEA BROWN BOVERI	ITE-27N
SR 3.3.8.1.3-1.d	ENS-SWG1A-27/62-2A	G13.18.6.3-007	ASEA BROWN BOVERI	ITE-27N

SR 3.3.8.1.3-1.d	ENS-SWG1A-27/62-2B	G13.18.6.3-007	ASEA BROWN BOVERI	ITE-27N
SR 3.3.8.1.3-1.d	ENS-SWG1A-27/62-2C	G13.18.6.3-007	ASEA BROWN BOVERI	ITE-27N
SR 3.3.8.1.3-1.d	ENS-SWG1B-27/62-2A	G13.18.6.3-007	ASEA BROWN BOVERI	ITE-27N
SR 3.3.8.1.3-1.d	ENS-SWG1B-27/62-2B	G13.18.6.3-007	ASEA BROWN BOVERI	ITE-27N
SR 3.3.8.1.3-1.d	ENS-SWG1B-27/62-2C	G13.18.6.3-007	ASEA BROWN BOVERI	ITE-27N
SR 3.3.8.1.3-1.d	ENS-SWG1A-27/62-2A	G13.18.6.3-008	ASEA BROWN BOVERI	ITE-27N
SR 3.3.8.1.3-1.d	ENS-SWG1A-27/62-2B	G13.18.6.3-008	ASEA BROWN BOVERI	ITE-27N
SR 3.3.8.1.3-1.d	ENS-SWG1A-27/62-2C	G13.18.6.3-008	ASEA BROWN BOVERI	ITE-27N
SR 3.3.8.1.3-1.d	ENS-SWG1B-27/62-2A	G13.18.6.3-008	ASEA BROWN BOVERI	ITE-27N
SR 3.3.8.1.3-1.d	ENS-SWG1B-27/62-2B	G13.18.6.3-008	ASEA BROWN BOVERI	ITE-27N
SR 3.3.8.1.3-1.d	ENS-SWG1B-27/62-2C	G13.18.6.3-008	ASEA BROWN BOVERI	ITE-27N
SR 3.3.8.1.3-1.d	ENS-SWG1A-62-2	G13.18.6.3-009	ASEA BROWN BOVERI	ITE-62K
SR 3.3.8.1.3-1.d	ENS-SWG1B-62-2	G13.18.6.3-009	ASEA BROWN BOVERI	ITE-62K
SR 3.3.8.1.3-1.e	ENS-SWG1A-27/62-2A	G13.18.6.3-007	ASEA BROWN BOVERI	ITE-27N
SR 3.3.8.1.3-1.e	ENS-SWG1A-27/62-2B	G13.18.6.3-007	ASEA BROWN BOVERI	ITE-27N
SR 3.3.8.1.3-1.e	ENS-SWG1A-27/62-2C	G13.18.6.3-007	ASEA BROWN BOVERI	ITE-27N
SR 3.3.8.1.3-1.e	ENS-SWG1B-27/62-2A	G13.18.6.3-007	ASEA BROWN BOVERI	ITE-27N
SR 3.3.8.1.3-1.e	ENS-SWG1B-27/62-2B	G13.18.6.3-007	ASEA BROWN BOVERI	ITE-27N
SR 3.3.8.1.3-1.e	ENS-SWG1B-27/62-2C	G13.18.6.3-007	ASEA BROWN BOVERI	ITE-27N
SR 3.3.8.1.3-1.e	ENS-SWG1A-27/62-2A	G13.18.6.3-008	ASEA BROWN BOVERI	ITE-27N
SR 3.3.8.1.3-1.e	ENS-SWG1A-27/62-2B	G13.18.6.3-008	ASEA BROWN BOVERI	ITE-27N
SR 3.3.8.1.3-1.e	ENS-SWG1A-27/62-2C	G13.18.6.3-008	ASEA BROWN BOVERI	ITE-27N

SR 3.3.8.1.3-1.e	ENS-SWG1B-27/62-2A	G13.18.6.3-008	ASEA BROWN BOVERI	ITE-27N
SR 3.3.8.1.3-1.e	ENS-SWG1B-27/62-2B	G13.18.6.3-008	ASEA BROWN BOVERI	ITE-27N
SR 3.3.8.1.3-1.e	ENS-SWG1B-27/62-2C	G13.18.6.3-008	ASEA BROWN BOVERI	ITE-27N
SR 3.3.8.1.3-1.e	ENS-SWG1A-62-6	G13.18.6.3-009	ASEA BROWN BOVERI	ITE-62K
SR 3.3.8.1.3-1.e	ENS-SWG1B-62-6	G13.18.6.3-009	ASEA BROWN BOVERI	ITE-62K
SR 3.3.8.1.3-2.a	E22-S004-27N1	G13.18.6.3-012	GENERAL ELECTRIC CO	NGV13B
SR 3.3.8.1.3-2.a	E22-S004-27N2	G13.18.6.3-012	GENERAL ELECTRIC CO	NGV13B
SR 3.3.8.1.3-2.a	E22-S004-27S1	G13.18.6.3-012	GENERAL ELECTRIC CO	NGV13B
SR 3.3.8.1.3-2.a	E22-S004-27S2	G13.18.6.3-012	GENERAL ELECTRIC CO	NGV13B
SR 3.3.8.1.3-2.a	E22-S004-27S3	G13.18.6.3-012	GENERAL ELECTRIC CO	NGV13B
SR 3.3.8.1.3-2.a	E22-S004-27S4	G13.18.6.3-012	GENERAL ELECTRIC CO	NGV13B
SR 3.3.8.1.3-2.b	E22-S004-62S1	G13.18.6.3-013	GENERAL ELECTRIC CO	SAM11B
SR 3.3.8.1.3-2.b	E22-S004-62S2	G13.18.6.3-013	GENERAL ELECTRIC CO	SAM11B
SR 3.3.8.1.3-2.b	E22-S004-62S3	G13.18.6.3-014	AMERACE CORP (Agastat)	ETR
SR 3.3.8.1.3-2.b	E22-S004-62S4	G13.18.6.3-014	AMERACE CORP (Agastat)	ETR
SR 3.3.8.1.3-2.c	E22-S004-27/62-1	G13.18.6.3-007	ASEA BROWN BOVERI	ITE-27N
SR 3.3.8.1.3-2.c	E22-S004-27/62-2	G13.18.6.3-007	ASEA BROWN BOVERI	ITE-27N
SR 3.3.8.1.3-2.c	E22-S004-27/62-1	G13.18.6.3-008	ASEA BROWN BOVERI	ITE-27N
SR 3.3.8.1.3-2.c	E22-S004-27/62-2	G13.18.6.3-008	ASEA BROWN BOVERI	ITE-27N
SR 3.3.8.1.3-2.d	E22-S004-62S5	G13.18.6.3-014	AMERACE CORP (Agastat)	ETR14D3E004
SR 3.3.8.1.3-2.d	E22-S004-62S6	G13.18.6.3-014	AMERACE CORP (Agastat)	ETR14D3E004
SR 3.3.8.1.3-2.e	E22-S004-27/62-1	G13.18.6.3-007	ASEA BROWN BOVERI	ITE-27N
SR 3.3.8.1.3-2.e	E22-S004-27/62-2	G13.18.6.3-007	ASEA BROWN BOVERI	ITE-27N
SR 3.3.8.1.3-2.e	E22-S004-27/62-1	G13.18.6.3-008	ASEA BROWN BOVERI	ITE-27N
SR 3.3.8.1.3-2.e	E22-S004-27/62-2	G13.18.6.3-008	ASEA BROWN BOVERI	ITE-27N
SR 3.3.8.2.2.a	C71-S003A-59N	G13.18.6.3-005	GENERAL ELECTRIC CO	914E175

SR 3.3.8.2.2.a	C71-S003B-59N	G13.18.6.3-005	GENERAL ELECTRIC CO	914E175
SR 3.3.8.2.2.a	C71-S003C-59N	G13.18.6.3-005	GENERAL ELECTRIC CO	914E175
SR 3.3.8.2.2.a	C71-S003D-59N	G13.18.6.3-005	GENERAL ELECTRIC CO	914E175
SR 3.3.8.2.2.a	C71-S003E-59N	G13.18.6.3-005	GENERAL ELECTRIC CO	914E175
SR 3.3.8.2.2.a	C71-S003F-59N	G13.18.6.3-005	GENERAL ELECTRIC CO	914E175
SR 3.3.8.2.2.a	C71-S003G-59N	G13.18.6.3-005	GENERAL ELECTRIC CO	914E175
SR 3.3.8.2.2.a	C71-S003H-59N	G13.18.6.3-005	GENERAL ELECTRIC CO	914E175
SR 3.3.8.2.2.b	C71-S003A-27N	G13.18.6.3-004	GENERAL ELECTRIC CO	914E175
SR 3.3.8.2.2.b	C71-S003B-27N	G13.18.6.3-004	GENERAL ELECTRIC CO	914E175
SR 3.3.8.2.2.b	C71-S003C-27N	G13.18.6.3-004	GENERAL ELECTRIC CO	914E175
SR 3.3.8.2.2.b	C71-S003D-27N	G13.18.6.3-004	GENERAL ELECTRIC CO	914E175
SR 3.3.8.2.2.b	C71-S003E-27N	G13.18.6.3-004	GENERAL ELECTRIC CO	914E175
SR 3.3.8.2.2.b	C71-S003F-27N	G13.18.6.3-004	GENERAL ELECTRIC CO	914E175
SR 3.3.8.2.2.b	C71-S003G-27N	G13.18.6.3-004	GENERAL ELECTRIC CO	914E175
SR 3.3.8.2.2.b	C71-S003H-27N	G13.18.6.3-004	GENERAL ELECTRIC CO	914E175
SR 3.3.8.2.2.c	C71-S003A-081	G13.18.6.3-001	GENERAL ELECTRIC CO	914E175
SR 3.3.8.2.2.c	C71-S003B-081	G13.18.6.3-001	GENERAL ELECTRIC CO	914E175
SR 3.3.8.2.2.c	C71-S003C-081	G13.18.6.3-001	GENERAL ELECTRIC CO	914E175
SR 3.3.8.2.2.c	C71-S003D-081	G13.18.6.3-001	GENERAL ELECTRIC CO	914E175
SR 3.3.8.2.2.c	C71-S003E-081	G13.18.6.3-001	GENERAL ELECTRIC CO	914E175
SR 3.3.8.2.2.c	C71-S003F-081	G13.18.6.3-001	GENERAL ELECTRIC CO	914E175
SR 3.3.8.2.2.c	C71-S003G-081	G13.18.6.3-001	GENERAL ELECTRIC CO	914E175
SR 3.3.8.2.2.c	C71-S003H-081	G13.18.6.3-001	GENERAL ELECTRIC CO	914E175
SR 3.3.8.2.2.c	C71-S003A-62	G13.18.6.3-003	GENERAL ELECTRIC CO	914E175
SR 3.3.8.2.2.c	C71-S003B-62	G13.18.6.3-003	GENERAL ELECTRIC CO	914E175
SR 3.3.8.2.2.c	C71-S003C-62	G13.18.6.3-003	GENERAL ELECTRIC CO	914E175
SR 3.3.8.2.2.c	C71-S003D-62	G13.18.6.3-003	GENERAL ELECTRIC CO	914E175
SR 3.3.8.2.2.c	C71-S003E-62	G13.18.6.3-003	GENERAL ELECTRIC CO	914E175
SR 3.3.8.2.2.c	C71-S003F-62	G13.18.6.3-003	GENERAL ELECTRIC CO	914E175
SR 3.3.8.2.2.c	C71-S003G-62	G13.18.6.3-003	GENERAL ELECTRIC CO	914E175
SR 3.3.8.2.2.c	C71-S003H-62	G13.18.6.3-003	GENERAL ELECTRIC CO	914E175