Entergy

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September 11, 2003

Re: Indian Point Unit No. 2
Docket No. 50-247
NL-03-137

Document Control Desk
U.S. Nuclear Regulatory Commission
Mail Station O-P1-17
Washington, DC 20555-0001

Subject: Supplement 7 to the Indian Point 2 License Amendment Request for Conversion to Improved Standard Technical Specifications

Reference:
1) Entergy letter (NL-02-016) to NRC, "License Amendment Request (LAR 02-005) Conversion to Improved Standard Technical Specifications," dated March 27, 2002
2) Entergy letter (NL-02-092) to NRC, "Supplement 1 to the Indian Point 2 License Amendment Request for Conversion to Improved Standard Technical Specifications," dated July 10, 2002
3) Entergy letter (NL-03-035) to NRC, "Supplement 2 to the Indian Point 2 License Amendment Request for Conversion to Improved Standard Technical Specifications," dated February 26, 2003
4) Entergy letter (NL-03-081) to NRC, "Supplement 3 to the Indian Point 2 License Amendment Request for Conversion to Improved Standard Technical Specifications," dated May 19, 2003
5) Entergy letter (NL-03-107) to NRC, "Supplement 4 to the Indian Point 2 License Amendment Request for Conversion to Improved Standard Technical Specifications," dated June 26, 2003
6) Entergy letter (NL-03-116) to NRC, "Supplement 5 to the Indian Point 2 License Amendment Request for Conversion to Improved Standard Technical Specifications," dated July 15, 2003
7) Entergy letter (NL-03-127) to NRC, "Supplement 6 to the Indian Point 2 License Amendment Request for Conversion to Improved Standard Technical Specifications," dated August 6, 2003
8) NRC Letter to Consolidated Edison, "Indian Point Nuclear Generating Station Unit No.2, Changes to Technical Specification Bases (TAC No. M86204)," dated June 21, 1994
9) NRC Letter to Entergy Nuclear Operations, Inc., "Indian Point Nuclear Generating Unit No.2–Improved Technical Specification (ITS) Conversion–ITS 3.3.2, 3.3.3, 3.3.4, 3.3.5, 3.3.6, and B3.7.10-Comments (TAC No. MB4739)," dated August 29, 2003

A001

Dear Sir:

By letter dated March 27, 2002 (Reference 1), as supplemented by letters dated July 10, 2002, February 26, 2003, May 19, 2003, June 26, 2003, July 15, 2003, and August 6, 2003 (References 2, 3, 4, 5, 6, and 7 respectively), Entergy Nuclear Operations, Inc. (Entergy) requested to amend the Indian Point 2 (IP2) Plant Operating License, Appendices A and B, "Technical Specifications." The proposed amendment converts the IP2 Current Technical Specifications (CTS) to Improved Technical Specifications (ITS) in accordance with NUREG 1431, "Standard Technical Specifications—Westinghouse Plants," Rev. 2.

This letter supplements References 1 through 7 to reflect the results of extensive discussions with your staff regarding the Limiting Safety System Settings (LSSS) required by 10 CFR 50.36(c)(1) to be included in the proposed IP2 ITS. Based on these discussions, Entergy is maintaining the current IP2 licensing basis in the proposed ITS by including, as Allowable Values, administrative limits that were applied to the CTS nominal trip setpoints when determining operability under the CTS. As described in Reference 8, the staff has previously reviewed the IP2 methodology for establishing the administrative limits and concluded that these limits serve the same function as the Allowable Value defined in the Standard Technical Specifications and plant setpoint methodology. The use of the "Allowable Value" as the LSSS in the plant Technical Specifications is consistent with the guidance provided in Regulatory Guide 1.105, "Setpoints for Safety-Related Instrumentation." As part of this administrative change, the nominal trip setpoints provided in the CTS are being relocated to a document controlled by Entergy in accordance with the requirements of 10 CFR 50.59, "Changes, tests and experiments."

Additionally, this supplement incorporates the resolution of the miscellaneous outstanding comments to various sections of the proposed IP2 ITS provided by the staff in Reference 9.

Finally, in anticipation that this transmittal will be the final supplement to the proposed IP2 ITS, Entergy has performed a complete cover-to-cover review of the submittal and has corrected minor inconsistencies and editorial errors in the specifications and bases. For your convenience in reviewing the final resolution of the comments contained in Reference 9, as well as the corrigenda changes, hand mark-ups and clean, typed copies of all of the affected pages are included as Attachments 1 and 2 to this letter.

The no significant hazards determination included with References 1 through 7 required no revision as a result of the changes being incorporated by Supplement 7. Therefore, it remains Entergy's conclusion that the conversion of the Indian Point 2 Technical Specifications to Improved Technical Specifications involves no significant hazards consideration as defined by 10 CFR 50.92.

As previously discussed in Supplement 6 (Reference 7), there are currently no outstanding CTS license amendments requests (LARs) for IP2 and Entergy does not anticipate the submittal of any LARs that would require review and approval prior to IP2 ITS implementation.

Implementation of the IP2 ITS will involve the performance of a number of new or modified Surveillance Requirements, some of which involve more restrictive requirements than those imposed by the CTS. Entergy intends to treat these new or more restrictive requirements as being met at the time of implementation, with the first scheduled performance to be completed within the required frequency commencing from the date of implementation.

As was done with References 1, 2, 3, 4, 5, 6, and 7, the material constituting Supplement 7 to the ITS submittal is enclosed herewith on CD-ROM. The Supplement 7 CD-ROM includes the following:

- The information originally transmitted by References 1, 2, 3, 4, 5, 6, and 7;
- A copy of this cover letter and attachments; and
- The IP2 CTS through Amendment 237.

This supplement and the enclosed CD-ROM were prepared in accordance with the guidance provided in NRC Regulatory Issue Summary 2001–05, "Guidance on Submitting Documents to the NRC by Electronic Information Exchange or on CD-ROM." In accordance with 10 CFR 50.91, a copy of this submittal and the associated attachments are being submitted to the designated New York State official.

There are no commitments contained in this letter.

Should you or your staff have any questions regarding this matter, please contact me at (914) 734-5336.

Sincerely,

William S. Blair
IP2 ITS Project Manager

Attachments
Enclosure

cc: see page 4

cc: (w/o attachments and enclosure)

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ATTACHMENT 1 TO NL-03-137

Marked–up Pages Affected by Supplement 7

Entergy Nuclear Operations, Inc.
Indian Point Unit No. 2
Docket No. 50-247

1.0 USE AND APPLICATION

1.1 Definitions

- NOTE -
The defined terms of this section appear in capitalized type and are applicable throughout these Technical Specifications and Bases.

Term	Definition
ACTIONS	ACTIONS shall be that part of a Specification that prescribes Required Actions to be taken under designated Conditions within specified Completion Times.
ACTUATION LOGIC TEST	An ACTUATION LOGIC TEST shall be the application of various simulated or actual input combinations in conjunction with each possible interlock logic state required for OPERABILITY of a logic circuit and the verification of the required logic output. The ACTUATION LOGIC TEST, as a minimum, shall include a continuity check of output devices.
AXIAL FLUX DIFFERENCE (AFD)	AFD shall be the difference in normalized flux signals between the top and bottom halves of a two section excore neutron detector.
CHANNEL CALIBRATION	A CHANNEL CALIBRATION shall be the adjustment, as necessary, of the channel output such that it responds within the necessary range and accuracy to known values of the parameter that the channel monitors. The CHANNEL CALIBRATION shall encompass all devices in the channel required for channel OPERABILITY. Calibration of instrument channels with resistance temperature detector (RTD) or thermocouple sensors may consist of an inplace qualitative assessment of sensor behavior and normal calibration of the remaining adjustable devices in the channel. The CHANNEL CALIBRATION may be performed by means of any series of sequential, overlapping, or total channel steps.
CHANNEL CHECK	A CHANNEL CHECK shall be the qualitative assessment, by observation, of channel behavior during operation. This determination shall include, where possible, comparison of the channel indication and status to other indications or status derived from independent instrument channels measuring the same parameter.

1.1 Definitions

CHANNEL OPERATIONAL TEST (COT)	A COT shall be the injection of a simulated or actual signal into the channel as close to the sensor as practicable to verify OPERABILITY of all devices in the channel required for channel OPERABILITY. The COT shall include adjustments, as necessary, of the required alarm, interlock, and trip setpoints required for channel OPERABILITY such that the setpoints are within the necessary range and accuracy. The COT may be performed by means of any series of sequential, overlapping, or total channel steps.
CORE ALTERATION	CORE ALTERATION shall be the movement of any fuel, sources, or reactivity control components, within the reactor vessel with the vessel head removed and fuel in the vessel. Suspension of CORE ALTERATIONS shall not preclude completion of movement of a component to a safe position.
CORE OPERATING LIMITS REPORT (COLR)	The COLR is the unit specific document that provides cycle specific parameter limits for the current reload cycle. These cycle specific parameter limits shall be determined for each reload cycle in accordance with Specification 5.6.5. Plant operation within these limits is addressed in individual Specifications.
DOSE EQUIVALENT I-131	DOSE EQUIVALENT I-131 shall be that concentration of I-131 (microcuries/gram) that alone would produce the same thyroid dose as the quantity and isotopic mixture of I-131, I-132, I-133, I-134, and I-135 actually present. The thyroid dose conversion factors used for this calculation shall be those listed in Table III of TID-14844, AEC, 1962, "Calculation of Distance Factors for Power and Test Reactor Sites," or those listed in Table E-7 of Regulatory Guide 1.109, Rev. 1, NRC, 1977, or ICRP 30, Supplement to Part 1, page 192-212, Table titled, "Committed Dose Equivalent in Target Organs or Tissues per Intake of Unit Activity".
$\bar{E}$ - AVERAGE DISINTEGRATION ENERGY	$\bar{E}$ shall be the average (weighted in proportion to the concentration of each radionuclide in the reactor coolant at the time of sampling) of the sum of the average beta and gamma energies per disintegration (in MeV) for isotopes, other than iodines, with half lives > 30 minutes, making up at least 95% of the total noniodine activity in the coolant.

1.1 Definitions

OPERABLE - OPERABILITY

A system, subsystem, train, component, or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified safety function(s) and when all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication, and other auxiliary equipment that are required for the system, subsystem, train, component, or device to perform its specified safety function(s) are also capable of performing their related support function(s).

PHYSICS TESTS

PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation. These tests are:

a. Described in, Chapter 13, "Tests and Operations." ~~of the~~ UFSAR

b. Authorized under the provisions of 10 CFR 50.59, or

c. Otherwise approved by the Nuclear Regulatory Commission.

QUADRANT POWER TILT RATIO (QPTR)

QPTR shall be the ratio of the maximum upper excore detector calibrated output to the average of the upper excore detector calibrated outputs, or the ratio of the maximum lower excore detector calibrated output to the average of the lower excore detector calibrated outputs, whichever is greater.

RATED THERMAL POWER (RTP)

RTP shall be a total reactor core heat transfer rate to the reactor coolant of 3114.4 MWt.

1.4 Frequency

DESCRIPTION (continued)

1. The Surveillance is not required to be met in the MODE or other specified condition to be entered: or

2. The Surveillance is required to be met in the MODE or other specified condition to be entered, but has been performed within the specified Frequency (i.e., it is current) and is known not to be failed; or

3. The Surveillance is required to be met, but not performed, in the MODE or other specified condition to be entered, and is known not to be failed.

Examples 1.4-3, 1.4-4, 1.4-5, and 1.4-6 discusses these special situations.

EXAMPLES

The following examples illustrate the various ways that Frequencies are specified. In these examples, the Applicability of the LCO (LCO not shown) is MODES 1, 2, and 3.

BASES

LCO 3.0.3 (continued)

The time limits of LCO 3.0.3 allow 37 hours for the unit to be in MODE 5 when a shutdown is required during MODE 1 operation. If the unit is in a lower MODE of operation when a shutdown is required, the time limit for reaching the next lower MODE applies. If a lower MODE is reached in less time than allowed, however, the total allowable time to reach MODE 5, or other applicable MODE, is not reduced. For example, if MODE 3 is reached in 2 hours, then the time allowed for reaching MODE 4 is the next 11 hours, because the total time for reaching MODE 4 is not reduced from the allowable limit of 13 hours. Therefore, if remedial measures are completed that would permit a return to MODE 1, a penalty is not incurred by having to reach a lower MODE of operation in less than the total time allowed.

In MODES 1, 2, 3, and 4, LCO 3.0.3 provides actions for Conditions not covered in other Specifications. The requirements of LCO 3.0.3 do not apply in MODES 5 and 6 because the unit is already in the most restrictive Condition required by LCO 3.0.3. The requirements of LCO 3.0.3 do not apply in other specified conditions of the Applicability (unless in MODE 1, 2, 3, or 4) because the ACTIONS of individual Specifications sufficiently define the remedial measures to be taken.

Exceptions to LCO 3.0.3 are provided in instances where requiring a unit shutdown, in accordance with LCO 3.0.3, would not provide appropriate remedial measures for the associated condition of the unit. An example of this is in LCO 3.7.11, "Spent Fuel Pit Water Level." LCO 3.7.11 has an Applicability of "During movement of irradiated fuel assemblies in the spent fuel ~~storage~~ pit." Therefore, this LCO can be applicable in any or all MODES. If the LCO and the Required Actions of LCO 3.7.11 are not met while in MODE 1, 2, or 3, there is no safety benefit to be gained by placing the unit in a shutdown condition. The Required Action of LCO 3.7.11 of "Suspend movement of irradiated fuel assemblies in the fuel ~~storage~~ pit" is the appropriate Required Action to complete in lieu of the actions of LCO 3.0.3. These exceptions are addressed in the individual Specifications.

LCO 3.0.4

LCO 3.0.4 establishes limitations on changes in MODES or other specified conditions in the Applicability when an LCO is not met. It allows placing the unit in a MODE or other specified condition stated in that Applicability (e.g., the Applicability desired to be entered) when unit conditions are such that the requirements of the LCO would not be met, in accordance with LCO 3.0.4.a, LCO 3.0.4.b, or LCO 3.0.4.c.

BASES

ACTIONS (continued)

The required Completion Time of 7 days is adequate for preparing whatever operating restrictions or Surveillances that may be required to allow continued reactor operation.

B.1

If the core reactivity cannot be restored to within the 1% Δk/k limit, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours. If the SDM for MODE 3 is not met, then the boration required by the Required Actions for LCO 3.1.1 would occur. The allowed Completion Time is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.2.1

Core reactivity is verified by periodic comparisons of measured and predicted RCS boron concentrations. The comparison is made, considering that other core conditions are fixed or stable, including control rod position, moderator temperature, fuel temperature, fuel depletion, xenon concentration, and samarium concentration.

This Surveillance must be performed prior to entering MODE 1 following each refueling as an initial check on core conditions and design calculations at BOC. This Surveillance is performed again within the initial 60 EFPD after entering MODE 1 following each refueling in order to adjust (normalize) the predicted reactivity values to the measured core reactivity. This SR is then required to be performed every 31 EFPD after the performance used for normalization. This Frequency is acceptable because of the slow rate of core changes due to fuel depletion and because of the presence of other indicators (QPTR, AFD, etc.) that provide prompt indication of an anomaly. The SR is modified by a Note. The Note indicates that the normalization of predicted core reactivity to the measured value, if performed, must take place within the first 60 effective full power days (EFPD) after each fuel loading. This allows sufficient time for core conditions to reach steady state, but prevents operation for a large fraction of the fuel cycle without establishing a benchmark for the design calculations.

BASES

APPLICABLE SAFETY ANALYSES (continued)

MTC satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii). Even though it is not directly observed and controlled from the control room, MTC is considered an initial condition process variable because of its dependence on boron concentration.

LCO

LCO 3.1.3 requires the MTC to be within specified limits of the COLR to ensure that the core operates within the assumptions of the accident analysis. During the reload core safety evaluation, the MTC is analyzed to determine that its values remain within the bounds of the original accident analysis during operation.

Assumptions made in safety analyses require that the MTC be less positive than a given upper bound and more positive than a given lower bound. The MTC is most positive at BOC; this upper bound must not be exceeded. This maximum upper limit occurs at BOC, all rods out (ARO), hot zero power conditions. At EOC the MTC takes on its most negative value, when the lower bound becomes important. This LCO exists to ensure that both the upper and lower bounds are not exceeded.

During operation, therefore, the conditions of the LCO can only be ensured through measurement. The Surveillance checks at BOC and EOC on MTC provide confirmation that the MTC is behaving as anticipated so that the acceptance criteria are met.

The LCO establishes a maximum positive value that cannot be exceeded. The BOC positive limit and the EOC negative limit are established in the COLR to allow specifying limits for each particular cycle. This permits the unit to take advantage of improved fuel management and changes in unit operating schedule.

APPLICABILITY

Technical Specifications place both LCO and SR values on MTC, based on the safety analysis assumptions described above.

In MODE 1, the limits on MTC must be maintained to ensure that any accident initiated from THERMAL POWER operation will not violate the design assumptions of the accident analysis. In MODE 2 with the reactor critical, the upper limit must also be maintained to ensure that startup and subcritical accidents (such as the uncontrolled CONTROL ROD assembly or group withdrawal) will not violate the assumptions of the accident analysis.

3.1 REACTIVITY CONTROL SYSTEMS

3.1.4 Rod Group Alignment Limits

LCO 3.1.4 All shutdown and control rods shall be OPERABLE.

AND

Individual indicated rod positions shall be within the following limits:

a. When THERMAL POWER is > 85% RTP, the difference between each individual indicated rod position and its group step counter demand position shall be within the limits specified in Table 3.1.4-1 for the group step counter demand position; and

b. When THERMAL POWER is ≤ 85% RTP, the difference between each individual indicated rod position and its group step counter demand position shall be ≤ 24 steps.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more rod(s) inoperable.	A.1.1 Verify SDM to be within the limits specified in the COLR.	1 hour
	OR	
	A.1.2 Initiate boration to restore SDM to within limit.	1 hour
	AND	
	A.2 Be in MODE 3.	6 hours
B. One rod not within alignment limits.	B.1 Restore rod to within alignment limits.	1 hour
	OR	

BASES

APPLICABLE SAFETY ANALYSES

Control rod misalignment accidents are analyzed in the safety analysis (References 4 and 5). The acceptance criteria for addressing control rod inoperability or misalignment are that:

a. There be no violations of:

   1. Specified acceptable fuel design limits or

   2. Reactor Coolant System (RCS) pressure boundary integrity and

b. The core remains subcritical after accident transients.

Two types of misalignment are distinguished. During movement of a control rod group, one rod may stop moving, while the other rods in the group continue. This condition may cause excessive power peaking. The second type of misalignment occurs if one rod fails to insert upon a reactor trip and remains stuck fully withdrawn. This condition requires an evaluation to determine that sufficient reactivity worth is held in the control rods to meet the SDM requirement, with the maximum worth rod stuck fully withdrawn.

Two types of analysis are performed in regard to static rod misalignment (Ref. 5). With control banks at their insertion limits, one type of analysis considers the case when any one rod is completely inserted into the core. The second type of analysis considers the case of a completely withdrawn single rod from a bank inserted to its insertion limit. Satisfying limits on departure from nucleate boiling ratio in both of these cases bounds the situation when a rod is misaligned.

When reactor power is > 85% RTP, an indicated misalignment of ± 12 steps (± 7.5 inches) between individual rod positions ~~(IRPI)~~ and the group step counter demand position will not cause the power peaking factor limits to be exceeded. This limit assumes a maximum IRPI instrument error of ± 12 steps (± 7.5 inches) allowing for an actual misalignment of ± 24 steps (± 15 inches). However, when the group step counter demand position is > 209 steps, it is acceptable for the IRPI to indicate misalignment greater than + 12 steps (i.e., may be up to + 16 steps) as specified in Table 3.1.4-1 without accounting for peaking factor margin. This is acceptable because the top of active fuel (TAF) is at 221 steps. With group step counter demand position > 209 steps and IRPI deviation > + 12 steps, the IRPI determined rod position is above the top of active fuel where it will not result in increased peaking factors for increased misalignments. Similarly, allowable negative deviation limits may increase by 1 step for every step of group step counter demand position over the top of active fuel as specified in Table 3.1.4-1. These rod misalignment limits were justified in Reference 5 and approved in Reference 6.

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i.e.,

BASES

APPLICABLE SAFETY ANALYSES (continued)

When reactor power is ≤ 85% RTP, an indicated misalignment of ± 24 steps (± 15 inches) between individual rod (RPI) positions and the group step counter demand position will not cause the power peaking factor limits to be exceeded. This limit assumes a maximum instrument error of ± 12 steps (± 7.5 inches) allowing for an actual misalignment of ± 36 steps (± 22.5 inches). These rod misalignment limits were justified in Reference 5 and approved in Reference 6.

As explained in Reference 5, the rod alignment limit analyses were performed using two distinct models of the IP2 core. These modes models addressed large variations in cycle length, number of feed assemblies, fuel enrichments and burnable poisons and are expected to bound any current or future fuel management strategies. Therefore, the results of the rod misalignment analyses are considered to be cycle independent.

Another type of misalignment occurs if one RCCA fails to insert upon a reactor trip and remains stuck fully withdrawn. This condition is assumed in the evaluation to determine that the required SDM is met with the maximum worth RCCA also fully withdrawn (Ref. 5).

The Required Actions in this LCO ensure that either deviations from the alignment limits will be corrected or that THERMAL POWER will be adjusted so that excessive local linear heat rates (LHRs) will not occur, and that the requirements on SDM and ejected rod worth are preserved.

Continued operation of the reactor with a misaligned control rod is allowed if the heat flux hot channel factor ($F_Q(Z)$) and the nuclear enthalpy hot channel factor ($F^N_{\Delta H}$) are verified to be within their limits in the COLR and the safety analysis is verified to remain valid. When a control rod is misaligned, the assumptions that are used to determine the rod insertion limits, AFD limits, and quadrant power tilt limits are not preserved. Therefore, the limits may not preserve the design peaking factors, and $F_Q(Z)$ and $F^N_{\Delta H}$ must be verified directly by incore mapping. Bases Section 3.2 (Power Distribution Limits) contains more complete discussions of the relation of $F_Q(Z)$ and $F^N_{\Delta H}$ to the operating limits.

Shutdown and control rod OPERABILITY and alignment are directly related to power distributions and SDM, which are initial conditions assumed in safety analyses. Therefore they satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES

ACTIONS (continued)

An alternative to realigning a single misaligned RCCA to the group average position is to align the remainder of the group to the position of the misaligned RCCA. However, this must be done without violating the bank sequence, overlap, and insertion limits specified in LCO 3.1.5, "Shutdown Bank Insertion Limits," and LCO 3.1.6, "Control Bank Insertion Limits." The Completion Time of 1 hour gives the operator sufficient time to adjust the rod positions in an orderly manner.

B.2.1.1 and B.2.1.2

With a misaligned rod, SDM must be verified to be within limit or boration must be initiated to restore SDM to within limit.

Power operation may continue with one RCCA trippable but misaligned, provided that SDM is verified within 1 hour. The Completion Time of 1 hour represents the time necessary for determining the actual unit SDM and, if necessary, aligning and starting the necessary systems and components to initiate boration.

B.2.2, B.2.3, B.2.4, B.2.5, and B.2.6

For continued operation with a misaligned rod, RTP must be reduced, SDM must periodically be verified within limits, hot channel factors ($F_Q(Z)$ and $F^N_{\Delta H}$) must be verified within limits, and the safety analyses must be re-evaluated to confirm continued operation is permissible.

Reduction of power to 75% RTP ensures that local LHR increases due to a misaligned RCCA will not cause the core design criteria to be exceeded. The Completion Time of 2 hours gives the operator sufficient time to accomplish an orderly power reduction without challenging the Reactor Protection System.

When a rod is known to be misaligned, there is a potential to impact the SDM. Since the core conditions can change with time, periodic verification of SDM is required. A Frequency of 12 hours is sufficient to ensure this requirement continues to be met.

Verifying that $F_Q(Z)$, as approximated by ~~and~~ $F^C_Q(Z)$ and $F^W_Q(Z)$, and $F^N_{\Delta H}$ are within the required limits ensures that current operation at 75% RTP with a rod misaligned is not resulting in power distributions that may invalidate safety analysis assumptions at full power. The Completion Time of 72 hours allows sufficient time to obtain flux maps of the core power distribution using the incore flux mapping system and to calculate $F_Q(Z)$ and $F^N_{\Delta H}$.

BASES

ACTIONS (continued)

Once current conditions have been verified acceptable, time is available to perform evaluations of accident analysis to determine that core limits will not be exceeded during a Design Basis Event for the duration of operation under these conditions. The accident analyses presented in Reference 5 that may be adversely affected will be evaluated to ensure that the analysis results remain valid for the duration of continued operation under these conditions. A Completion Time of 5 days is sufficient time to obtain the required input data and to perform the analysis.

C.1

When Required Actions cannot be completed within their Completion Time, the unit must be brought to a MODE or Condition in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours, which obviates concerns about the development of undesirable xenon or power distributions. The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner and without challenging the plant systems.

D.1.1 and D.1.2

More than one control rod becoming misaligned from its group average position is not expected, and has the potential to reduce SDM. Therefore, SDM must be evaluated. One hour allows the operator adequate time to determine SDM. Restoration of the required SDM, if necessary, requires increasing the RCS boron concentration to provide negative reactivity, as described in the Bases of LCO 3.1.1. The required Completion Time of 1 hour for initiating boration is reasonable, based on the time required for potential xenon redistribution, the low probability of an accident occurring, and the steps required to complete the action. This allows the operator sufficient time to align the required valves and start the boric acid pumps. Boration will continue until the required SDM is restored.

A power reduction to ≤ 85% RTP will result in the LCO being met if IRPIs associated with all groups indicate within ± 24 steps (± 15 inches) of the group step counter demand position. If LCO 3.1.4.b is met when ≤ 85% RTP, realigning RCCAs to within the limits of LCO 3.1.4.a is required only as a condition for increasing power to > 85% RTP.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The shutdown bank insertion limits preserve an initial condition assumed in the safety analyses and, as such, satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The shutdown banks must be within their insertion limits any time the reactor is critical or approaching criticality. This ensures that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM following a reactor trip.

The shutdown bank insertion limits are defined in the COLR.

APPLICABILITY

The shutdown banks must be within their insertion limits, with the reactor in MODES 1 and 2. This ensures that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM following a reactor trip. The shutdown banks do not have to be within their insertion limits in MODE 3, unless an approach to criticality is being made. In MODE 3, 4, 5, or 6, the shutdown banks are fully inserted in the core and contribute to the SDM. Refer to LCO 3.1.1 for SDM requirements in MODES 3, 4, and 5. LCO 3.9.1, "Boron Concentration," ensures adequate SDM in MODE 6.

The Applicability requirements have been modified by a Note indicating the LCO requirement is suspended during SR 3.1.4.2. This SR verifies the freedom of the rods to move, and requires the shutdown bank to move below the LCO limits, which would normally violate the LCO.

ACTIONS

A.1.1, A.1.2 and A.2

When one or more shutdown banks is not within insertion limits, 2 hours is allowed to restore the shutdown banks to within the insertion limits. This is necessary because the available SDM may be significantly reduced, with one or more of the shutdown banks not within their insertion limits. Also, verification of SDM or initiation of boration within 1 hour is required, since the SDM in MODES 1 and 2 is ensured by adhering to the control and shutdown bank insertion limits (see LCO 3.1.1). If shutdown banks are not within their insertion limits, then SDM will be verified by performing a reactivity balance calculation, considering the effects listed in the BASES for SR 3.1.1.1.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.6 Control Bank Insertion Limits

BASES

BACKGROUND

The insertion limits of the shutdown and control rods are initial assumptions in all safety analyses that assume rod insertion upon reactor trip. The insertion limits directly affect core power and fuel burnup distributions and assumptions of available SDM, and initial reactivity insertion rate.

The applicable criteria for these reactivity and power distribution design requirements are 10 CFR 50, Appendix A, GDC 10, "Reactor Design," GDC 26, "Reactivity Control System Redundancy and Protection," GDC 28, "Reactivity Limits" (Ref. 1), and 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors" (Ref. 2). Limits on control rod insertion have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

The rod cluster control assemblies (RCCAs) are divided among control banks and shutdown banks. Each bank may be further subdivided into two groups to provide for precise reactivity control. A group consists of two or more RCCAs that are electrically paralleled to step simultaneously. A bank of RCCAs consists of two groups that are moved in a staggered fashion, but always within one step of each other. IP2 has four control banks and four shutdown banks. See LCO 3.1.4, "Rod Group Alignment Limits," for control and shutdown rod OPERABILITY and alignment requirements, and LCO 3.1.7, "Rod Position Indication," for position indication requirements.

The control bank insertion limits are specified in the COLR. The control banks are required to be at or above the insertion limit lines. The COLR also indicates how the control banks are moved in an overlap pattern. Overlap is the distance travelled together by two control banks. The predetermined position of control bank C, at which control bank D will begin to move with bank C on a withdrawal, will be at 118 steps for a fully withdrawn position of 231 steps. The fully withdrawn position is defined in the COLR.

The control banks are used for precise reactivity control of the reactor. The positions of the control banks are normally controlled automatically by the Rod Control System, but can also be manually controlled. They are capable of adding reactivity very quickly (compared to borating or diluting).

BASES

BACKGROUND (continued)

The power density at any point in the core must be limited, so that the fuel design criteria are maintained. Together, LCO 3.1.4, LCO 3.1.5, "Shutdown Bank Insertion Limits," LCO 3.1.6, LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," provide limits on control component operation and on monitored process variables, which ensure that the core operates within the fuel design criteria.

The shutdown and control bank insertion and alignment limits, AFD, and QPTR are process variables that together characterize and control the three dimensional power distribution of the reactor core. Additionally, the control bank insertion limits control the reactivity that could be added in the event of a rod ejection accident, and the shutdown and control bank insertion limits ensure the required SDM is maintained.

Operation within the subject LCO limits will prevent fuel cladding failures that would breach the primary fission product barrier and release fission products to the reactor coolant in the event of a loss of coolant accident (LOCA), loss of flow, ejected rod, or other accident requiring termination by a Reactor Protection System (RPS) trip function.

APPLICABLE SAFETY ANALYSES

The shutdown and control bank insertion limits, AFD, and QPTR LCOs are required to prevent power distributions that could result in fuel cladding failures in the event of a LOCA, loss of flow, ejected rod, or other accident s requiring termination by an RPS trip function.

The acceptance criteria for addressing shutdown and control bank insertion limits and inoperability or misalignment are that:

a. There be no violations of:

   1. Specified acceptable fuel design limits or

   2. Reactor Coolant System pressure boundary integrity and

b. The core remains subcritical after accident transients.

As such, the shutdown and control bank insertion limits affect safety analysis involving core reactivity and power distributions (Ref. 3).

BASES

APPLICABLE SAFETY ANALYSES (continued)

Reference 6 allows special test exceptions (STEs) to be included as part of the LCO that they affect. It was decided, however, to retain this STE as a separate LCO because it was less cumbersome and provided additional clarity.

LCO

This LCO allows the reactor parameters of MTC and minimum temperature for criticality to be outside their specified limits. In addition, it allows selected control and shutdown rods to be positioned outside of their specified alignment and insertion limits. Operation beyond specified limits is permitted for the purpose of performing PHYSICS TESTS and poses no threat to fuel integrity, provided the SRs are met.

The requirements of LCO 3.1.3, LCO 3.1.4, LCO 3.1.5, LCO 3.1.6, and LCO 3.4.2 may be suspended during the performance of PHYSICS TESTS provided:

a. RCS lowest loop average temperature is $\geq$ 541°F,

b. SDM is within the limits provided in the COLR, and

c. THERMAL POWER is < 5% RTP.

APPLICABILITY

This LCO is applicable when performing low power PHYSICS TESTS. The Applicability is stated as "During PHYSICS TESTS initiated in MODE 2" to ensure that the 5% RPT maximum power level is not exceeded. Should the THERMAL POWER EXCEED 5% RPT, and consequently the unit enters MODE 1, this Applicability statement prevents exiting this Specification and its Required Actions.

ACTIONS

<u>A.1 and A.2</u>

If the SDM requirement is not met, boration must be initiated promptly. A Completion Time of 15 minutes is adequate for an operator to correctly align and start the required systems and components. The operator should begin boration with the best source available for the plant conditions. Boration will be continued until SDM is within limit.

Suspension of PHYSICS TESTS exceptions requires restoration of each of the applicable LCOs to within specification.

BASES

ACTIONS (continued)

B.1

If Required Actions A.1 through A.4 are not met within their associated Completion Times, the plant must be placed in a mode or condition in which the LCO requirements are not applicable. This is done by placing the plant in at least MODE 2 within 6 hours.

This allowed Completion Time is reasonable based on operating experience regarding the amount of time it takes to reach MODE 2 from full power operation in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.1.1 is modified by a Note. The Note applies during the first power ascension after a refueling. It states that THERMAL POWER may be increased until an equilibrium power level has been achieved at which a power distribution map can be obtained. This allowance is modified by a Frequency condition that requires verification that $F_Q(Z)$ is within specified limits after a power rise of more than 10% RTP over the THERMAL POWER at which it was last verified to be within specified limits. Because $F_Q(Z)$ could not have previously been measured in this reload core, there is a second Frequency condition, applicable only for reload cores, that requires determination of these parameters before exceeding 75% RTP. This ensures that some determination of $F_Q(Z)$ is made at a lower power level at which adequate margin is available before going to 100% RTP. Also, this Frequency condition, together with the Frequency condition requiring verification of $F_Q(Z)$ following a power increase of more than 10%, ensures performance as soon as RTP (or any other level for extended operation) is achieved. In the absence of these Frequency conditions, it is possible to increase power to RTP and operate for 31 days without verification of $F_Q(Z)$. The Frequency condition is not intended to require verification of $F_Q(Z)$ after every 10% increase in power level above the last verification. It only requires verification after a power level is achieved for extended operation that is 10% higher than that power at which $F_Q(Z)$ was last measured.

SR 3.2.1.1

Verification that $F_Q(Z)$ is within its specified limits involves increasing $F_Q^M(Z)$ to allow for manufacturing tolerance and measurement uncertainties in order to obtain $F_Q(Z)$. Specifically, $F_Q^M(Z)$ is the measured value of $F_Q(Z)$ obtained from incore flux map results and $F_Q(Z) = F_Q^M(Z)$ 1.0815. $F_Q(Z)$ is then compared to its specified limits.

BASES

APPLICABLE SAFETY ANALYSES

Limits on $F^N_{\Delta H}$ preclude core power distributions that exceed the following fuel design limits:

a. There must be at least 95% probability at the 95% confidence level (the 95/95 DNB criterion) that the hottest fuel rod in the core does not experience a DNB condition,

b. During a large break loss of coolant accident (LOCA), peak cladding temperature (PCT) must not exceed 2200°F,

c. During an ejected rod accident, the energy deposition to the fuel must not exceed 200 cal/gm (Ref. 1), and

d. Fuel design limits required by GDC 26 (Ref. 2) for the condition when control rods must be capable of shutting down the reactor with a minimum required SDM with the highest worth control rod stuck fully withdrawn.

For transients that may be DNB limited, the Reactor Coolant System flow and $F^N_{\Delta H}$ are the core parameters of most importance. The limits on $F^N_{\Delta H}$ ensure that the DNB design basis is met for normal operation, operational transients, and any transients arising from events of moderate frequency. The DNB design basis is met by limiting the minimum DNBR to the 95/95 DNB criterion of 1.17 using the WRB-1 CHF correlation for 15 X 15 fuel. This value provides a high degree of assurance that the hottest fuel rod in the core does not experience a DNB.

The allowable $F^N_{\Delta H}$ limit increases with decreasing power level. This functionality in $F^N_{\Delta H}$ is included in the analyses that provide the Reactor Core Safety Limits (SLs) of SL 2.1.1. Therefore, any DNB events in which the calculation of the core limits is modeled implicitly use this variable value of $F^N_{\Delta H}$ in the analyses. Likewise, all transients that may be DNB limited are assumed to begin with an initial $F^N_{\Delta H}$ as a function of power level defined by the COLR limit equation.

The LOCA safety analysis indirectly models $F^N_{\Delta H}$ as an input parameter. The Nuclear Heat Flux Hot Channel Factor ($F_Q(Z)$) and the axial peaking factors are inserted directly into the LOCA safety analyses that verify the acceptability of the resulting peak cladding temperature (Ref. 3).

the following

BASES

APPLICABLE SAFETY ANALYSES (continued)

The fuel is protected in part by Technical Specifications, which ensure that the initial conditions assumed in the safety and accident analyses remain valid: ~~The following LCOs ensure this:~~ LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," LCO 3.1.6, "Control Bank Insertion Limits," LCO 3.2.2, "Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$)," and LCO 3.2.1, "Heat Flux Hot Channel Factor ($F_Q(Z)$)."

$F^N_{\Delta H}$ and $F_Q(Z)$ are measured periodically using the movable incore detector system. Measurements are generally taken with the core at, or near, steady state conditions. Core monitoring and control under transient conditions (Condition 1 events) are accomplished by operating the core within the limits of the LCOs on AFD, QPTR, and Bank Insertion Limits.

$F^N_{\Delta H}$ satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

$F^N_{\Delta H}$ shall be maintained within the limits of the relationship provided in the COLR.

The $F^N_{\Delta H}$ limit identifies the coolant flow channel with the maximum enthalpy rise. This channel has the least heat removal capability and thus the highest probability for a DNB.

The limiting value of $F^N_{\Delta H}$, described by the equation contained in the COLR, is the design radial peaking factor used in the unit safety analyses.

A power multiplication factor in this equation includes an additional margin for higher radial peaking from reduced thermal feedback and greater control rod insertion at low power levels. The limiting value of $F^N_{\Delta H}$ is allowed to increase 0.3% for every 1% RTP reduction in THERMAL POWER.

APPLICABILITY

The $F^N_{\Delta H}$ limits must be maintained in MODE 1 to preclude core power distributions from exceeding the fuel design limits for DNBR and PCT. Applicability in other modes is not required because there is either insufficient stored energy in the fuel or insufficient energy being transferred to the coolant to require a limit on the distribution of core power. Specifically, the design bases events that are sensitive to $F^N_{\Delta H}$ in other modes (MODES 2 through 5) have significant margin to DNB, and therefore, there is no need to restrict $F^N_{\Delta H}$ in these modes.

BASES

ACTIONS

A.1.1

With $F^N_{\Delta H}$ exceeding its limit, the unit is allowed 4 hours to restore $F^N_{\Delta H}$ to within its limits. This restoration may, for example, involve realigning any misaligned rods or reducing power enough to bring $F^N_{\Delta H}$ within its power dependent limit. When the $F^N_{\Delta H}$ limit is exceeded, the DNBR limit is not likely violated in steady state operation, because events that could significantly perturb the $F^N_{\Delta H}$ value (e.g., static control rod misalignment) are considered in the safety analyses. However, the DNBR limit may be violated if a DNB limiting event occurs. Thus, the allowed Completion Time of 4 hours provides an acceptable time to restore $F^N_{\Delta H}$ to within its limits without allowing the plant to remain in an unacceptable condition for an extended period of time.

Condition A is modified by a Note that requires that Required Actions A.2 and A.3 must be completed whenever Condition A is entered. Thus, if power is not reduced because this Required Action is completed within the 4 hour time period, Required Action A.2 nevertheless requires another measurement and calculation of $F^N_{\Delta H}$ within 24 hours in accordance with SR 3.2.2.1.

However, if power is reduced below 50% RTP, Required Action A.3 requires that another determination of $F^N_{\Delta H}$ must be done prior to exceeding 50% RTP, prior to exceeding 75% RTP, and within 24 hours after reaching or exceeding 95% RTP. A single performance of SR 3.0.2.1 may be used to satisfy requirements of both Required Action A.2 and A.3, if it is completed within 24 hours of entering Condition A.

2

A.1.2.1 and A.1.2.2

If the value of $F^N_{\Delta H}$ is not restored to within its specified limit either by adjusting a misaligned rod or by reducing THERMAL POWER, the alternative option is to reduce THERMAL POWER to < 50% RTP in accordance with Required Action A.1.2.1 and reduce the Power Range Neutron Flux - High to ≤ 55% RTP in accordance with Required Action A.1.2.2. Reducing RTP to < 50% RTP increases the DNB margin and does not likely cause the DNBR limit to be violated in steady state operation. The reduction in trip setpoints ensures that continuing operation remains at an acceptable low power level with adequate DNBR margin. The allowed Completion Time of 4 hours for Required Action A.1.2.1 is consistent with those allowed for in Required Action A.1.1 and provides an acceptable time to reach the required power level from full power operation without allowing

BASES

ACTIONS (continued)

the plant to remain in an unacceptable condition for an extended period of time. The Completion Times of 4 hours for Required Actions A.1.1 and A.1.2.1 are not additive.

The allowed Completion Time of 72 hours to reset the trip setpoints per Required Action A.1.2.2 recognizes that, once power is reduced, the safety analysis assumptions are satisfied and there is no urgent need to reduce the trip setpoints. This is a sensitive operation that may inadvertently trip the Reactor Protection System.

A.2

Once the power level has been reduced per Required Action A.1.2.1, an incore flux map (SR 3.2.2.1) must be obtained and the measured value of $F^N_{\Delta H}$ verified not to exceed the allowed limit at the lower power level. The unit is provided 20 additional hours to perform this task over and above the 4 hours allowed by either Action A.1.1 or Action A.1.2.1. The Completion Time of 24 hours is acceptable because of the increase in the DNB margin, which is obtained at lower power levels, and the low probability of having a DNB limiting event within this 24 hour period. Additionally, operating experience has indicated that this Completion Time is sufficient to obtain the incore flux map, perform the required calculations, and evaluate $F^N_{\Delta H}$. A single performance of SR 3.2.2.1 may be used to satisfy requirements of both Required Action A.2 and A.3, if it is completed within 24 hours of entering Condition A.

A.3

Verification that $F^N_{\Delta H}$ is within its specified limits after an out of limit occurrence ensures that the cause that led to the $F^N_{\Delta H}$ exceeding its limit is corrected, and that subsequent operation proceeds within the LCO limit. This Action demonstrates that the $F^N_{\Delta H}$ limit is within the LCO limits prior to exceeding 50% RTP, again prior to exceeding 75% RTP, and within 24 hours after THERMAL POWER is ≥ 95% RTP. A single performance of SR 3.2.2.1 may be used to satisfy requirements of both Required Action A.2 and A.3, if it is completed within 24 hours of entering Condition A.

This Required Action is modified by a Note that states that THERMAL POWER does not have to be reduced prior to performing this Action.

3.2 POWER DISTRIBUTION LIMITS

3.2.3 AXIAL FLUX DIFFERENCE (AFD) (Constant Axial Offset Control (CAOC) Methodology)

LCO 3.2.3 The AFD:

a. Shall be maintained within the target band about the target flux difference. The target band is specified in the COLR.

b. May deviate outside the target band with THERMAL POWER < 90% RTP but ≥ 50% RTP, provided AFD is within the acceptable operation limits and cumulative penalty deviation time is ≤ 1 hour during the previous 24 hours. The acceptable operation limits are specified in the COLR.

c. May deviate outside the target band with THERMAL POWER < 50% RTP.

- NOTES -

1. The AFD shall be considered outside the target band when two or more OPERABLE excore channels indicate AFD to be outside the target band.

2. With THERMAL POWER ≥ 50% RTP, penalty deviation time shall be accumulated on the basis of a 1 minute penalty deviation for each 1 minute of power operation with AFD outside the target band. space

3. With THERMAL POWER < 50% RTP and > 15 % RTP, penalty deviation time shall be accumulated on the basis of a 0.5 minute penalty deviation for each 1 minute of power operation with AFD outside the target band.

4. A total of 16 hours of operation may be accumulated with AFD outside the target band without penalty deviation time during surveillance of power range channels in accordance with SR 3.3.1.6, provided AFD is maintained within acceptable operation.

APPLICABILITY: MODE 1 with THERMAL POWER > 15% RTP.

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
	A.4 Reevaluate safety analyses and confirm results remain valid for duration of operation under this condition.	Prior to increasing THERMAL POWER above the limit of Required Action A.1
	AND	
	A.5 ----- - NOTE - 1. Perform Required Action A.5 only after Required Action A.4 is completed. 2. Required Action A.6 shall be completed whenever Required Action A.5 is performed. -----	S
	Normalize excore detectors to restore QPTR to within limit.	Prior to increasing THERMAL POWER above the limit of Required Action A.1
	AND	
	A.6 ----- - NOTE - Perform Required Action A.6 only after Required Action A.5 is completed. -----	
	Perform SR 3.2.1.1 and SR 3.2.2.1.	Within 24 hours after achieving equilibrium conditions at RTP not to exceed 48 hours after increasing THERMAL POWER above the limit of Required Action A.1

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.4 QUADRANT POWER TILT RATIO (QPTR)

BASES

BACKGROUND

The QPTR limit ensures that the gross radial power distribution remains consistent with the design values used in the safety analyses. Precise radial power distribution measurements are made during startup testing, after refueling, and periodically during power operation.

The power density at any point in the core must be limited so that the fuel design criteria are maintained. Together, LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," LCO 3.2.4, and LCO 3.1.6, "Control Bank Insertion Limits," provide limits on process variables that characterize and control the three dimensional power distribution of the reactor core. Control of these variables ensures that the core operates within the fuel design criteria and that the power distribution remains within the bounds used in the safety analyses.

APPLICABLE SAFETY ANALYSES

This LCO precludes core power distributions that violate the following fuel design criteria:

a. During a large break loss of coolant accident, the peak cladding temperature must not exceed 2200°F (Ref. 1),

b. During a loss of forced reactor coolant flow accident, there must be at least 95% probability at the 95% confidence level (the 95/95 departure from nucleate boiling (DNB) criterion) that the hot fuel rod in the core does not experience a DNB condition,
hottest

c. During an ejected rod accident, the energy deposition to the fuel must not exceed 200 cal/gm (Ref. 2), and

d. The control rods must be capable of shutting down the reactor with a minimum required SDM with the highest worth control rod stuck fully withdrawn (Ref. 3).

The LCO limits on the AFD, the QPTR, the Heat Flux Hot Channel Factor ($F_Q(Z)$), the Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$), and control bank insertion are established to preclude core power distributions that exceed the safety analyses limits.

BASES

BACKGROUND (continued)

Technical specifications contain values related to the OPERABILITY of equipment required for safe operation of the facility. OPERABLE is defined in technical specifications as "...being capable of performing its safety functions(s)." For automatic protective devices, the required safety function is to ensure that a SL is not exceeded and therefore the LSSS as defined by 10 CFR 50.36 is the same as the OPERABILITY limit for these devices. However, use of the trip setpoint to define OPERABILITY in technical specifications and its corresponding designation as the LSSS required by 10 CFR 50.36 would be an overly restrictive requirement if it were applied as an OPERABILITY limit for the "as found" value of a protective device setting during a surveillance. This would result in technical specification compliance ~~problems~~, and ~~as well as~~ reports and corrective actions required by the rule which are not necessary to ensure safety. For example, an automatic protective device with a setting that has been found to be different from the trip setpoint due to some drift of the setting may still be OPERABLE since drift is to be expected. This expected drift would have been specifically accounted for in the setpoint methodology for calculating the trip setpoint and thus the automatic protective action would still have ensured that the SL would not be exceeded with the "as found" setting of the protective device. Therefore, the device would still be OPERABLE since it would have performed its safety function and the only corrective action required would be to reset the device to the trip setpoint to account for further drift during the next surveillance interval.

There is also some point beyond which the device would have not been able to perform its function due, for example, to greater than expected drift. This value needs to be specified in the technical specifications in order to define OPERABILITY of the devices and is designated as the Allowable Value which, as stated above, is the same as the LSSS.

The Allowable Value specified in Table 3.3.1-1 serves as the LSSS such that a channel is OPERABLE if the actuation point is found not to exceed the Allowable Value during the CHANNEL OPERATIONAL TEST (COT). As such, the Allowable Value differs from the limiting setpoint by an amount primarily equal to the expected instrument loop uncertainties, such as drift and calibration effect, during the surveillance interval. In this manner, the actual setting of the device will still meet the LSSS definition and ensure that a Safety Limit is not exceeded at any given point of time as long as the device has not drifted beyond that expected during the surveillance interval. Note that, although the channel is "OPERABLE" under these circumstances, the trip setpoint should be left adjusted to a value within the established trip setpoint calibration tolerance band, in accordance with uncertainty

BASES

BACKGROUND (continued)

assumptions stated in the referenced setpoint methodology (as-left criteria), and confirmed to be operating within the statistical allowances of the uncertainty terms assigned. If the actual setting of the device is found to have exceeded the as-found allowance, the channel would be evaluated to determine Technical Specification OPERABILITY. The results of this evaluation would result in corrective action including those actions required by 10 CFR 50.36 when automatic protective devices do not function as required.

Allowable Values for each RPS function are listed in Table 3.3.1-1. Trip Setpoints that ensure that the Allowable Values are not exceeded over the calibration interval are controlled administratively outside of the Technical Specifications.

During AOOs, which are those events expected to occur one or more times during the unit life, the acceptable limits are:

1. The Departure from Nucleate Boiling Ratio (DNBR) shall be maintained above the Safety Limit (SL) value to prevent departure from nucleate boiling (DNB),

2. Fuel centerline melt shall not occur, and

3. The RCS pressure SL of 2735 psig shall not be exceeded.

Operation within the SLs of Specification 2.0, "Safety Limits (SLs)," also maintains the above values and assures that offsite dose will be within the ~~10 CFR 50 and~~ 10 CFR 50.67 criteria during AOOs.

Accidents are events that are analyzed even though they are not expected to occur during the unit life. The acceptable limit during accidents is that offsite dose shall be maintained within 10 CFR 50.67 limits. 10 CFR 50.67 limits are used in the evaluation of proposed design basis changes with respect to potential reactor accidents of exceedingly low probability of occurrence and low risk of public exposure to radiation. Meeting the acceptable dose limit for an accident category is considered having acceptable consequences for that event.

The RPS instrumentation is segmented into four distinct but interconnected modules as identified below:

BASES

BACKGROUND (continued)

1. Field transmitters or process sensors: provide a measurable electronic signal based upon the physical characteristics of the parameter being measured,

2. Signal Process Control and Protection System, including Analog Protection System, Nuclear Instrumentation System (NIS), field contacts, and protection channel sets: provides signal conditioning, bistable setpoint comparison, process algorithm actuation, compatible electrical signal output to protection system devices, and control board/control room/miscellaneous indications,

3. RPS Automatic Trip Logic, including input, logic, and output: initiates proper reactor shutdown and/or ESF actuation in accordance with the defined logic, which is based on the bistable outputs from the signal process control and protection system, and

4. Reactor trip switchgear, including reactor trip breakers (RTBs) and bypass breakers: provide the means to interrupt power to the control rod drive mechanisms (CRDMs) and allows the rod cluster control assemblies (RCCAs), or "rods," to fall into the core and shut down the reactor. The bypass breakers allow testing of the RTBs at power.

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Field Transmitters or Sensors

To meet the design demands for redundancy and reliability, more than one, and often as many as four, field transmitters or sensors are used to measure unit parameters. In many cases, field transmitters or sensors that input to the Reactor Protection System (RPS) are shared with the ESFAS. In some cases, the same channels also provide control system inputs.

To account for the calibration tolerances and instrument drift, which are assumed to occur between calibrations, statistical allowances are provided in the trip setpoint. The OPERABILITY of each transmitter or sensor is determined by either "as-found" calibration data evaluated during the CHANNEL CALIBRATION or by qualitative assessment of field transmitter or sensor as related to the channel behavior observed during performance of the CHANNEL CHECK.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

OPERABILITY in MODE 1 ensures the Function is available to perform its decreasing power Functions in the event of a reactor shutdown. This Function must be OPERABLE in MODE 2 to ensure that core protection is provided during a startup or shutdown by the Power Range Neutron Flux, - Low and Intermediate Range Neutron Flux reactor trips. In MODE 3, 4, 5, or 6, this Function does not have to be OPERABLE because the reactor is not at power and the Source Range Neutron Flux reactor trip provides core protection.

e. Turbine First Stage Pressure

The Turbine First Stage Pressure (P-7 input) interlock is actuated when the pressure in the first stage of the high pressure turbine is greater than approximately 10% of the pressure consistent with 100% RTP. This is determined by one-out-of-two pressure detectors. The LCO requirement for this Function ensures that one of the inputs to the P-7 interlock is available.

The LCO requires two channels of Turbine First Stage Pressure interlock to be OPERABLE in MODE 1.

The Turbine First Stage Pressure (P-7 input) interlock must be OPERABLE when the turbine generator is operating. The interlock Function is not required OPERABLE in MODE 2, 3, 4, 5, or 6 because the turbine generator is not operating.

18. Reactor Trip Breakers

This trip Function applies to the RTBs exclusive of undervoltage and shunt trip mechanisms which are addressed in Function 19. The LCO requires two OPERABLE trains of trip breakers. A trip breaker train consists of all trip breakers associated with a single RPS logic train that are racked in, closed, and capable of supplying power to the Rod Control System. Thus, the train may consist of the main breaker, bypass breaker, or main breaker and bypass breaker, depending upon the system configuration. ~~Two OPERABLE trains ensure no single random failure can disable the RPS trip capability.~~

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BASES

ACTIONS (continued)

The Completion Time of 48 hours is reasonable considering that there are two automatic actuation trains and another manual initiation channel OPERABLE, and the low probability of an event occurring during this interval.

If the Manual Reactor Trip Function cannot be restored to OPERABLE status within the allowed 48 hour Completion Time, the unit must be brought to a MODE in which the requirement does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 additional hours (54 hours total time). The 6 additional hours to reach MODE 3 is reasonable, based on operating experience, to reach MODE 3 from full power operation in an orderly manner and without challenging unit systems. With the unit in MODE 3, ACTION C would apply to any inoperable Manual Reactor Trip Function if the Rod Control System is capable of rod withdrawal or one or more rods are not fully inserted.

C.1, C.2.1, and C.2.2

Condition C applies to the following reactor trip Functions in MODE 3, 4, or 5 with the Rod Control System capable of rod withdrawal or one or more rods not fully inserted:

- Manual Reactor Trip,
- RTBs,
- RTB Undervoltage and Shunt Trip Mechanisms, and
- Automatic Trip Logic.

This action addresses the train orientation of the RPS Automatic Trip Logic for these Functions. With one channel or train inoperable, the inoperable channel or train must be restored to OPERABLE status within 48 hours. If the affected Function(s) cannot be restored to OPERABLE status within the allowed 48 hour Completion Time, the unit must be placed in a MODE in which the requirement does not apply. To achieve this status, action must be initiated within the same 48 hours to ensure that all rods are fully inserted, and the Rod Control System must be placed in a condition incapable of rod withdrawal within the next hour. The additional hour provides sufficient time to accomplish the action in an orderly manner. With rods fully inserted and the Rod Control System incapable of rod withdrawal, these Functions are no longer required.

BASES

ACTIONS (continued)

If the inoperable channel cannot be placed in the trip condition within the specified Completion Time, the unit must be placed in a MODE where these Functions are not required OPERABLE. An additional 6 hours is allowed to place the unit in MODE 3. Six hours is a reasonable time, based on operating experience, to place the unit in MODE 3 from full power in an orderly manner and without challenging unit systems.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to 12 hours while performing routine surveillance testing (including associated repairs). The 12 hour time limit is justified in Reference 7. This allowance may be used to bypass an inoperable channel that is in trip to permit surveillance testing (including associated repairs) and setpoint adjustment of other channels. This allowance may also be used to bypass an otherwise OPERABLE channel during surveillance testing and setpoint adjustment.

F.1 and F.2

Condition F applies to the Intermediate Range Neutron Flux trip when THERMAL POWER is above the P-6 setpoint and below the P-10 setpoint and one channel is inoperable. Above the P-6 setpoint and below the P-10 setpoint, the NIS intermediate range detector performs the monitoring Functions. If THERMAL POWER is greater than the P-6 setpoint but less than the P-10 setpoint, 24 hours is allowed to reduce THERMAL POWER below the P-6 setpoint or increase to THERMAL POWER above the P-10 setpoint. The NIS Intermediate Range Neutron Flux channels must be OPERABLE when the power level is above the capability of the source range, P-6, and below the capability of the power range, P-10. If THERMAL POWER is greater than the P-10 setpoint, the NIS power range detectors perform the monitoring and protection functions and the intermediate range is not required. The Completion Times allow for a slow and controlled power adjustment above P-10 or below P-6 and take into account the redundant capability afforded by the redundant OPERABLE channel, and the low probability of its failure during this period. This action does not require the inoperable channel to be tripped because the Function uses one-out-of-two logic. Tripping one channel would trip the reactor. Thus, the Required Actions specified in this Condition are only applicable when channel failure does not result in reactor trip.

BASES

ACTIONS (continued)

- RCP Breaker Position,
- RCP Undervoltage, and
- RCP Underfrequency.

With one channel inoperable, the inoperable channel must be placed in the tripped condition within 72 hours. For the Pressurizer Pressure - Low, Pressurizer Water Level - High, Undervoltage RCPs, and Underfrequency RCPs trip Functions, placing the channel in the tripped condition when above the P-7 setpoint results in a condition requiring only one additional channel to initiate a reactor trip. For the Reactor Coolant Flow - Low ~~and RCP Breaker Position (Two Loops)~~ trip Function~~s~~, placing the channel in the tripped condition when above the P-8 setpoint results in a partial trip condition requiring only one additional channel in the same loop to initiate a reactor trip. ~~For the latter two trip Functions,~~ two tripped channels in two RCS loops are required to initiate a reactor trip when below the P-8 setpoint and above the P-7 setpoint. These Functions do not have to be OPERABLE below the P-7 setpoint because there are no loss of flow trips below the P-7 setpoint. There is insufficient heat production to generate DNB conditions below the P-7 setpoint. The 72 hours allowed to place the channel in the tripped condition is justified in Reference 8. An additional 6 hours is allowed to reduce THERMAL POWER to below P-7 if the inoperable channel cannot be restored to OPERABLE status or placed in trip within the specified Completion Time.

Allowance of this time interval takes into consideration the redundant capability provided by the remaining redundant OPERABLE channel, and the low probability of occurrence of an event during this period that may require the protection afforded by the Functions associated with Condition K.

The Required Actions have been modified by a Note that allows placing one channel in the bypassed condition for up to 12 hours while performing routine surveillance testing. The 12 hour time limit is justified in Reference 7. This allowance may be used to bypass an inoperable channel that is in trip to permit surveillance testing and setpoint adjustment of other channels. This allowance may also be used to bypass an otherwise OPERABLE channel during surveillance testing and setpoint adjustment.

BASES

ACTIONS (continued)

L.1 and L.2

Condition L applies to the RCP Breaker Position (Single Loop) reactor trip Function. There is one breaker position device per RCP breaker. With one channel inoperable, the inoperable channel must be restored to OPERABLE status within 6 hours. If the channel cannot be restored to OPERABLE status within the 6 hours, then THERMAL POWER must be reduced below the P-8 setpoint within the next 4 hours.

This places the unit in a MODE where the LCO is no longer applicable. This Function does not have to be OPERABLE below the P-8 setpoint because other RPS Functions provide core protection below the P-8 setpoint. The 6 hours allowed to restore the channel to OPERABLE status and the 4 additional hours allowed to reduce THERMAL POWER to below the P-8 setpoint are justified in Reference 8.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to 4 hours while performing online surveillance testing of the other channels. The 4 hour time limit is justified in Reference 8. This allowance may be used to bypass an inoperable channel that is in trip to permit surveillance testing (including associated repairs) of the other channels.

M.1 and M.2

placed in trip

Condition M applies to the RCP Breaker Position (Two Loops) reactor trip Function. There is one breaker position device per RCP breaker. With one channel inoperable, the inoperable channel must be ~~restored to OPERABLE status~~ within 6 hours. If the channel cannot be ~~restored to OPERABLE status~~ within the 6 hours, then THERMAL POWER must be reduced below the P-7 setpoint within the next 6 hours. This places the unit in a MODE where the LCO is no longer applicable.

place the channel in trip

This Function does not have to be OPERABLE below the P-7 setpoint because other RPS Functions provide core protection below the P-7 setpoint. The 6 hours allowed to ~~restore the channel to OPERABLE status~~ and the 6 additional hours allowed to reduce THERMAL POWER to below the P-7 setpoint are justified in Reference 8. The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to 4 hours while performing routine surveillance testing of the other channels. The 4 hour time limit is justified in Reference 8.

BASES

ACTIONS (continued)

The 24 hour time limit for the RPS Automatic Trip Logic train testing and maintenance is greater than the 4 hour time limit for RTBs, which the logic trains supports. The longer time limit for the Logic train (24 hours) is acceptable based on Reference 7.

P.1 and P.2

Condition P applies to the RTBs in MODES 1 and 2. These actions address the train orientation of the RPS for the RTBs. With one train inoperable, 24 hours is allowed for train corrective maintenance to restore the train to OPERABLE status or the unit must be placed in MODE 3 within the next 6 hours. The 24 hour Completion Time is justified in Reference 10. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems. Placing the unit in MODE 3 results in ACTION C entry while RTB(s) are inoperable.

The Required Actions have been modified by a Note that allows one train to be bypassed for up to 4 hours for surveillance testing, provided the other train is OPERABLE. This Note applies to RTB testing that is performed independently from the corresponding Logic train testing. For concurrent testing of the Logic and RTB, the 24 hour test time limit of Condition O applies. The 24 hour time is justified in Ref. 10.

Q.1 and Q.2

or trains

Condition Q applies to the P-6 and P-10 interlocks. With one or more channels inoperable for one-out-of-two or two-out-of-four coincidence logic, the associated interlock must be verified to be in its required state for the existing unit condition within 1 hour or the unit must be placed in MODE 3 within the next 6 hours. Verifying the interlock status manually accomplishes the interlock's Function. The Completion Time of 1 hour is based on operating experience and the minimum amount of time allowed for manual operator actions. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems. The 1 hour and 6 hour Completion Times are equal to the time allowed by LCO 3.0.3 for shutdown actions in the event of a complete loss of RPS Function.

BASES

ACTIONS (continued)

R.1 and R.2

or trains

Condition R applies to the P-7 and P-8 interlocks and the input to P-7 from turbine first stage pressure. With one or more channels inoperable for one-out-of-two or two-out-of-four coincidence logic, the associated interlock must be verified to be in its required state for the existing unit condition within 1 hour or the unit must be placed in MODE 2 within the next 6 hours. These actions are conservative for the case where power level is being raised. Verifying the interlock status manually accomplishes the interlock's Function. The Completion Time of 1 hour is based on operating experience and the minimum amount of time allowed for manual operator actions. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 2 from full power in an orderly manner and without challenging unit systems.

S.1 and S.2

Condition S applies to the RTB Undervoltage and Shunt Trip Mechanisms, or diverse trip features, in MODES 1 and 2. With one of the diverse trip features inoperable, it must be restored to an OPERABLE status within 48 hours or the unit must be placed in a MODE where the requirement does not apply. This is accomplished by placing the unit in MODE 3 within the next 6 hours (54 hours total time). The Completion Time of 6 hours is a reasonable time, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems. With the unit in MODE 3, ACTION C would apply to any inoperable RTB trip mechanism. ~~The affected RTB shall not be bypassed while one of the diverse features is inoperable except for the time required to perform maintenance to one of the diverse features. The allowable time for performing maintenance of the diverse features is 2 hours for the reasons stated under Condition P.~~

Error in TSIF

The Completion Time of 48 hours for Required Action S.1 is reasonable considering that in this Condition there is one remaining diverse feature for the affected RTB, and one OPERABLE RTB capable of performing the safety function and given the low probability of an event occurring during this interval.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.6

SR 3.3.1.6 is a calibration of the excore channels to the incore channels. If the measurements do not agree, the excore channels are not declared inoperable but must be calibrated to agree with the incore detector measurements. If the excore channels cannot be adjusted, the channels are declared inoperable. This Surveillance is performed to verify the f(ΔI) input to the overtemperature ΔT Function.

A Note modifies SR 3.3.1.6. The Note states that this Surveillance is required only if reactor power is > 50% RTP and that 24 hours is allowed for performing the first surveillance after reaching 50% RTP.

The Frequency of 92 EFPD is adequate based on industry operating experience, considering instrument reliability and operating history data for instrument drift. Additionally, this Frequency is consistent with the Frequency of SR 3.2.3.3 which measures the target flux differences and adjusts the target flux difference for each excore channel to the value measured at steady state conditions. The Frequency of 92 EFPDs recognizes that the target flux difference varies slowly with core burnup.

SR 3.3.1.7

SR 3.3.1.7 is the performance of a COT every 184 days.

A COT is performed on each required channel to ensure the entire channel will perform the intended Function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL OPERATIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

S

Setpoints must be within the Allowable Values specified in Table 3.3.1-1. The "as found" and "as left" values must also be recorded and reviewed for consistency with the assumptions of Reference 7 and 8. The difference between the current "as found" values and the previous test "as left" values must be consistent with the drift allowance used in the setpoint methodology. The setpoint shall be left set consistent with the assumptions of Reference 6 which incorporates the requirements of References 7 and 8.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.7 is modified by a Note that provides a 4 hour delay in the requirement to perform this Surveillance for source range instrumentation when entering MODE 3 from MODE 2. This Note allows a normal shutdown to proceed without a delay for testing in MODE 2 and for a short time in MODE 3 until the RTBs are open and SR 3.3.1.7 is no longer required to be performed. If the unit is to be in MODE 3 with the RTBs closed for > 4 hours this Surveillance must be performed prior to 4 hours after entry into MODE 3.

The Frequency of 184 days is justified in Reference 10.

SR 3.3.1.8

SR 3.3.1.8 is the performance of a COT as described in SR 3.3.1.7, except it is modified by a Note that this test shall include verification that the P-6 and P-10 interlocks are in their required state for the existing unit condition. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL OPERATIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. The Frequency is modified by a Note that allows this surveillance to be satisfied if it has been performed within 184 days of the Frequencies prior to reactor startup and four hours after reducing power below P-10 and P-6.

The Frequency of "prior to startup" ensures this surveillance is performed prior to critical operations and applies to the source, intermediate and power range low instrument channels. The Frequency of 12 hours after reducing power below P-10 (applicable to intermediate and power range low channels) and 4 hours after reducing power below P-6 (applicable to source range channels) allows a normal shutdown to be completed and the unit removed from the MODE of Applicability for this surveillance without a delay to perform the testing required by this surveillance.

BASES

SURVEILLANCE REQUIREMENTS (continued)

CHANNEL CALIBRATIONS must be performed consistent with the assumptions used in Reference 6. The difference between the current "as found" values and the previous test "as left" values must be consistent with the drift allowance used in the setpoint methodology.

The Frequency of 24 months is based on the assumption of a~~n~~ 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint methodology.

~~SR 3.3.1.10 is modified by a Note stating that this test shall include verification that the time constants are adjusted to the prescribed values where applicable.~~

SR 3.3.1.11

SR 3.3.1.11 is the performance of a CHANNEL CALIBRATION, as described in SR 3.3.1.10, every 24 months. This is a calibration of the channel other than the neutron detectors. This SR is modified by a Note stating that neutron detectors are excluded from the CHANNEL CALIBRATION. This is needed because CHANNEL CALIBRATION for the power range neutron detectors consists of a normalization of the detectors based on a power calorimetric and flux map performed above 15% RTP. This normalization of the power range neutron detectors is performed by SR 3.3.1.2 within 12 hours after exceeding 15% RTP.

The CHANNEL CALIBRATION for the neutron detector portion of the source range and intermediate range neutron detectors consists of obtaining the detector plateau or preamp discriminator curves, evaluating those curves, and comparing the curves to the manufacturer's data. This Surveillance is not required for the NIS power range detectors for entry into MODE 2 or 1, and is not required for the NIS intermediate range detectors for entry into MODE 2, because the unit must be in MODE 1 to perform SR 3.3.1.2 and the unit must be in at least MODE 2 to perform the test for the intermediate range detectors.

The 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 Surveillance when performed on the 24 month Frequency.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.12

SR 3.3.1.12 is the performance of a CHANNEL CALIBRATION, as described in SR 3.3.1.10, every 24 months. This SR includes verification that the electronic dynamic compensation time constants in Table 3.3.1-1, Notes 1 and 2, are set at the required values. Whenever a sensing element is replaced, the next required CHANNEL CALIBRATION of the resistance temperature detectors (RTD) sensors is accomplished by an in place cross calibration that compares the other sensing elements with the recently installed sensing element.

The Frequency is justified by the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.1.13

SR 3.3.1.13 is the performance of a COT of RPS interlocks every 24 months. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL OPERATIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

The Frequency is based on the known reliability of the interlocks and the multichannel redundancy available, and has been shown to be acceptable through operating experience.

Turbine Trip low Auto Stop Oil Pressure

SR 3.3.1.14

SR 3.3.1.14 is the performance of a TADOT of the Manual Reactor Trip, RCP Breaker Position, and the SI Input from ESFAS. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable TADOT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. This TADOT is performed every 24 months. The test shall independently verify the OPERABILITY of the tested functions including overlap with the

BASES

SURVEILLANCE REQUIREMENTS (continued)

undervoltage and shunt trip mechanisms for the Manual Reactor Trip Function for the Reactor Trip Breakers and Reactor Trip Bypass Breakers up to and including matrix contacts of RT-11/RT-12 from both manual trip actuating devices. The Reactor Trip Bypass Breaker test shall include testing of the automatic undervoltage trip and the shunt trip through the trip actuating devices.

The Frequency is based on the known reliability of the Functions and the multichannel redundancy available, and has been shown to be acceptable through operating experience.

Except for Turbine Trip Low Auto Stop Oil pressure,

The SR is modified by a Note that excludes verification of setpoints from the TADOT. ~~T~~he Functions affected have no setpoints associated with them.

REFERENCES

1. UFSAR, Chapter 7.
2. UFSAR, Chapter 6.
3. UFSAR, Chapter 14.
4. IEEE-279-1968.
5. 10 CFR 50.49.
6. Indian Point 2 Specification FIX-95-A-001, Guidelines for Preparation Of Instrument Loop Accuracy and Setpoint Determination Calculation.
7. WCAP-14333-P-A, Rev.1, Probabilistic Risk Analysis of the RPS and ESFAS Test Times and Completion Times.
8. WCAP-10271-P-A, Supplement 1, Rev. 1, May, 1986.
9. Safety Evaluation by the Office of Nuclear Reactor Regulation Related Indian Point 2 Proposed Increase in Licensed Thermal Power, January 29, 1990.
10. WCAP-15376-P-A, Rev.0, Risk Informed assessment of RTS and ESFAS Surveillance Test Intervals and Reactor Trip Breaker Test and Completion Times, October 2000.

2.3 LIMITING SAFETY SYSTEM SETTINGS, PROTECTIVE INSTRUMENTATION

A.2

~~Applicability~~

~~Applies to trip settings for instruments monitoring reactor power and reactor coolant pressure, temperature, flow, and pressurizer level.~~

~~Objective~~

~~To provide for automatic protective action such that the principal process variables do not exceed a safety limit.~~

Specifications

allowable values — L.1

1. Protective instrumentation for reactor trip settings shall be as follows:

A. Startup protection

L.1

T 3.3.1-1, #2b (1) High flux, power range (low setpoint): ≤ 25% of rated power. A.5

B. Core limit protection

L.1

T3.3.1-1, # 2a (1) High flux, power range (high setpoint): ≤ 109% of rated power. A.4

T3.3.1-1, #7b (2) High pressurizer pressure: ≤ 2363 psig. L.1 A.11

T3.3.1-1, #7a (3) Low pressurizer pressure: ≥ 1928 psig. L.1 A.10

T3.3.1-1, #5 (4) Overtemperature ΔT: A.8

T3.3.1-1 Note 1

$\Delta T \le \Delta T_o\ [K_1 - K_2 \left(\frac{1+T_1S}{1+T_2S}\right)(T - T') + K_3\ (P - P') - f\ (\Delta I)]$ A.8.f

where:

ΔT = Measured ΔT by hot and cold leg RTDs, °F

ΔT_o ≤ Indicated ΔT at rated power, °F A.8

T = Average temperature, °F

T' = Design full power T_{avg} at rated power, ≤ 579.2°F LA.5

T_1 = seconds

T_2 = seconds

S = Laplace Transform, sec^{-1}

L.1 A.8.f

 A.6.f

T3.3.1-1, #3 IRM allowable value L.1

T3.3.1-1, #4 SRM allowable value L.1 M.18

A.7.f

P = Pressurizer pressure, psig

P' = 2235 psig

$K_1 \le$ 1.22 LA.5

K_2 = 0.022

K_3 = 0.00095

A.8

and $f(\Delta I)$ is a function of the indicated difference between top and bottom detectors of the power-range nuclear ion chambers; with gains to be selected based on measured instrument response during plant startup tests such that: LA.4

T 3.3.1-1, Note 1

(i) ~~For $q_t - q_b$ between -36% and +7%, $f(\Delta I) = 0$, where q_t and q_b are percent rated power in the top and bottom halves of the core respectively, and $q_t + q_b$ is total power in percent of rated power;~~

(ii) ~~For each percent that the magnitude of $q_t - q_b$ exceeds -36%, the ΔT trip setpoint shall be automatically reduced by 2.14% of its value at rated power; and~~

(iii) ~~For each percent that the magnitude of $q_t - q_b$ exceeds +7%, the ΔT trip setpoint shall be automatically reduced by 2.15% of its value at rated power.~~ LA.5

T 3.3.1-1, #L (5) Overpower ΔT:

T 3.3.1-1, Note 2

$$\Delta T \le \Delta T_o \left[K_4 - K_5 \frac{dT}{dt} - K_6 (T - T')\right]$$

$\frac{\tau_3 s}{1+\tau_3 s}$ A.9.f

≤2.3% of ΔT span ~~L~~

A.9

where:

ΔT = Measured ΔT by hot and cold leg RTDs, ^oF

$\Delta T_o \le$ Indicated ΔT at rated power, ^oF

T = Average temperature, ^oF

T3.3.1-1, Note 2

T' = Indicated full power T_{avg} at rated power ≤ 579.2°F

K_4 ≤ 1.074

K_5 = Zero for decreasing average temperature

K_5 ≥ 0.188, for increasing average temperature (sec/°F)

K_6 ≥ 0.0015 for T ≥T'; K_6 = 0 for T < T'

$\frac{dT}{dt}$ = Rate of change of T_{avg}

LA.5 A.9

T3.3.1-1, #9 (6) Low reactor coolant loop flow: ~~L.1~~

(a) ≥ 92% of normal indicated loop flow. A.13

T3.3.1-1, #12 (b) Low reactor coolant pump frequency: ≥ 57.5 cps. L.1 A.17

T3.3.1-1, #11 (7) Undervoltage: ≥ 70% of normal voltage. ~~L.1~~ A.16

C. Other reactor trips

T3.3.1-1, #8 (1) High pressurizer water level: ≤ 90% of span. ~~L.1~~ A.12

T3.3.1-1, #13 (2) Low-low steam generator water level: ≥ 7% of narrow range instrument span. ~~L.1~~ A.18

T3.3.1-1, #17 2. Protective instrumentation ~~settings~~ Allowable Values for reactor trip interlocks shall satisfy the following conditions: ~~L.1~~

T3.3.1-1, #7a, #8, #10b, #11, #12 Notes (e) and (g) A. The reactor trips on low pressurizer pressure, high pressurizer level, and low reactor coolant flow for two or more loops shall be ~~un~~blocked when: ≤ P-10 ≤ 10% RTP ~~L.1~~ A.10 A.12 A.15

T3.3.1-1, #17d (1) ~~Power range nuclear flux ≥ 10% of rated power~~ or P-7 A.25

T3.3.1-1, #17e (2) Turbine first stage pressure ≥ 10% of equivalent full load. P-7 input L.1 A.26

T3.3.1-1, #17c T3.3.1-1, #10a and Note (f) B. The single loop loss of flow reactor trip may be bypassed when the power range nuclear instrumentation ~~indicates ≤ 60% of rated power~~ < P-8 setpoint A.24 A.14

Relocation of details explaining what is covered by tests listed in CTS Table 4.1-1 is a less restrictive administrative change (See ITS 3.3.1, DOC LA.3).

A.04.f Rev. 1

3.3.1: Reactor Protection System (RPS) Instrumentation

Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.1, Function 2.a, Power Range Neutron Flux-High.

Description of Change

~~CTS 2.3.1.B(1) establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the Power Range Neutron Flux-High at less than or equal to 109% RTP. This nominal trip setpoint was established based on Indian Point Nuclear Generating Station Unit No.2 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, and is considered conservative.~~

~~ITS 3.3.1, Function 2.a, Power Range Neutron Flux-High, uses an "Allowable Value" (i.e., as-found setpoint) as the Limiting Safety System Setting.~~

Justification for Change

~~Indian Point 2 is currently in the process of developing an allowable value of this function using a methodology consistent with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation." When completed, Indian Point 2 will submit to the NRC a copy of site specific methodology and the results. Upon NRC approval, the allowable values will be incorporated into the Improved Technical Specification submittal.~~

Use of "Allowable Values" (i.e., as-found setpoints) as the LSSS is a less restrictive change. These changes are described and justified in ITS 3.3.1, DOC L.1.

A.05 Rev. 1

3.3.1: Reactor Protection System (RPS) Instrumentation

Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of requirements for:
ITS 3.3.1, Function 2.b, Power Range Neutron Flux-Low.

Description of Change

ITS 3.3.1, Function 2.b, Power Range Neutron Flux-Low (trip), is equivalent to CTS 2.3.1.A(1), CTS Table 4.1-1, Item 1, and CTS Table 3.5-2, Function 2, Nuclear Flux Power Range, except that the ITS provides distinct requirements for both Power Range Neutron Flux-High and Neutron-Flux Low.

Justification for Change

This is an administrative change with no impact on safety because there are no changes to the existing requirements except as described and justified in the following sections:
a) describes changes in Applicability requirements;
b) describes changes in requirements for number of Operable channels;
c) describes changes to Required Actions for one inoperable channel;
d) describes changes for Required Actions for loss of function or extended loss of redundancy;
e) describes changes for Surveillance requirements; and,
f) describes changes for Allowable Values and Setpoints.
These descriptions reference discussions of change that justify any more or less restrictive changes that are described.

Relocation of details explaining what is covered by tests listed in CTS Table 4.1-1 is a less restrictive administrative change (See ITS 3.3.1, DOC LA.3).

A.05.f Rev. 1

3.3.1: Reactor Protection System (RPS) Instrumentation

Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.1, Function 2.b, Power Range Neutron Flux-Low.

Description of Change

CTS 2.3.1.A (1) establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the Power Range Neutron Flux-Low trip at less than or equal to 25% RTP. This nominal trip setpoint was established based on Indian Point Nuclear Generating Station Unit No.2 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, and is considered conservative.

ITS 3.3.1, Function 2.b, Power Range Neutron Flux-Low, uses an "Allowable Value" (i.e., as-found setpoint) as the Limiting Safety System Setting.

Justification for Change

Indian Point 2 is currently in the process of developing an allowable value of this function using a methodology consistent with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation." When completed, Indian Point 2 will submit to the NRC a copy of site specific methodology and the results. Upon NRC approval, the allowable values will be incorporated into the Improved Technical Specification submittal.

Use of "Allowable Values" (i.e., as-found setpoints) as the LSSS is a less restrictive change. These changes are described and justified in ITS 3.3.1, DOC L.1.

A.06 Rev. 1

3.3.1: Reactor Protection System (RPS) Instrumentation

Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of requirements for:
ITS 3.3.1, Function 3, Intermediate Range Neutron Flux.

Description of Change

ITS 3.3.1, Function 3, Intermediate Range Neutron Flux (trip), is equivalent to CTS Table 3.5-2, Function 3, Nuclear Flux Intermediate Range, and CTS Table 4.1-1, Item 2.

Justification for Change

This is an administrative change with no impact on safety because there are no changes to the existing requirements except as described and justified in the following sections:
a) describes changes in Applicability requirements;
b) describes changes in requirements for number of Operable channels;
c) describes changes to Required Actions for one inoperable channel;
d) describes changes for Required Actions for loss of function or extended loss of redundancy;
e) describes changes for Surveillance requirements; and,
f) describes changes for Allowable Values and Setpoints.
These descriptions reference discussions of change that justify any more or less restrictive changes that are described.

Relocation of details explaining what is covered by tests listed in CTS Table 4.1-1 is a less restrictive administrative change (See ITS 3.3.1, DOC LA.3).

A.06.f Rev. 1

3.3.1: Reactor Protection System (RPS) Instrumentation

Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.1, Function 3, Intermediate Range Neutron Flux.

Description of Change

CTS 2.3 does not establish a limiting safety system setting (allowable value) for the IRM Flux (trip) function although the trip must be set above the P-10 setpoint and is typically set below the Power Range Neutron Flux - Low trip setpoint (i.e. approximately 25% RTP) so that the IRM trip anticipates the Power Range Neutron Flux - Low trip. This nominal trip setpoint used in the plant was established based on Indian Point Nuclear Generating Station Unit No. 2 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, and is considered conservative.

ITS 3.3.1, Function 3, Intermediate Range Neutron Flux, Table 3.3.1-1 identifies the Technical Specification Allowable Value for this trip function as not applicable (NA) because the LCO 3.3.1, Function 2.b, Power Range Neutron Flux-Low, is used to bound the analysis for an uncontrolled control rod assembly withdrawal from a subcritical condition. The allowable value required for OPERABILITY of this trip function will be maintained in ITS Table 3.3.1-1 as part of the IP2 allowable value program. Inclusion in the ITS of a specific limit for the allowable value for this function is a more restrictive change that is addressed in DOC M.18. Use of "Allowable Values" (i.e., as-found setpoints) as the LSSS is a less restrictive change. This change is described and justified in ITS 3.3.1, DOC L.1.

Justification for Change

Indian Point 2 is currently in the process of developing an allowable value of this function using a methodology consistent with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation." When completed, Indian Point 2 will submit to the NRC a copy of site specific methodology and the results. Upon NRC approval, the allowable values will be incorporated into the Improved Technical Specification submittal.

Inclusion in the ITS of a specific limit for the allowable value for this function is a more restrictive change that is addressed in DOC M.18. Use of "Allowable Values" (i.e., as-found setpoints) as the LSSS is a less restrictive change. This change is described and justified in ITS 3.3.1, DOC L.1.

Intervals and Reactor Trip Breaker Test and Completion Times, October 2000, is described and justified in DOC L.12.

Requiring a Channel Operational Test of the Source Range Neutron Flux (trip) within 4 hours after reducing power below the P-6 setpoint if the reactor is not shutdown within those 4 hours is justified in ITS 3.3.1, DOC M.06.

Requiring a Channel Operational Test of the Source Range Neutron Flux (trip) within 4 hours after entering Mode 3 from Mode 2 and every 92 days thereafter if the CRD system is capable of rod withdrawal or one or more rods are not fully inserted is justified in ITS 3.3.1, DOC M.06.

The addition of ITS SR 3.3.1.11, Channel Calibration of the Source Range Neutron Flux (trip) function every 24 months is a more restrictive change (See ITS 3.3.1, DOC M.04).

A.07.f <u>3.3.1: Reactor Protection System (RPS) Instrumentation</u>

Rev. 1 <u>Category</u> Administrative: No Technical Changes

<u>DOC Summary:</u>

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.1, Function 4, Source Range Neutron (SRM) Flux.

<u>Description of Change</u>

CTS 2.3 does not establish a limiting safety system setting (allowable value) for the Source Range Flux (trip) function although it is typically set near the upper end of the source range indication. The nominal trip setpoint used in the plant was established based on Indian Point Nuclear Generating Station Unit No. 2 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, and is considered conservative.

Table 3.3.1-1 identifies the Technical Specification Allowable Value for this trip function as not applicable (NA) because the LCO 3.3.1, Function 2.b, Power Range Neutron Flux-Low, is used to bound the analysis for an uncontrolled control rod assembly withdrawal from a subcritical condition. The allowable value required for OPERABILITY of this trip function will be maintained in ITS Table 3.3.1-1 as part of the IP2 allowable value program. Inclusion in the ITS of a specific limit for the allowable value for this function is a more restrictive change that is addressed in DOC M.18. Use of "Allowable Values" (i.e., as-found setpoints) as the LSSS is a less restrictive change. This change is described and justified in ITS 3.3.1, DOC L.1.

<u>Justification for Change</u>

Indian Point 2 is currently in the process of developing an allowable value of this function using a methodology consistent with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation." When completed, Indian Point 2 will submit to the NRC a copy of site specific methodology and the results. Upon NRC approval, the allowable values will be incorporated into the Improved Technical Specification submittal.

Inclusion in the ITS of a specific limit for the allowable value for this function is a more restrictive change that is addressed in DOC M.18. Use of "Allowable Values" (i.e., as-found setpoints) as the LSSS is a less restrictive change. This change is described and justified in ITS 3.3.1, DOC L.1.

A.08.f Rev. 1 **3.3.1: Reactor Protection System (RPS) Instrumentation**

Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.1, Function 5, Overtemperature delta T.

Description of Change

CTS 2.3.1.B(4) establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the Overtemperature delta T function based on a calculation that includes input from various parameters as described in CTS 2.3.1.B(4). This nominal trip setpoint was established based on Indian Point Nuclear Generating Station Unit No. 2 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, and is considered conservative.

ITS 3.3.1, Function 5 (and associated acceptance criteria in Table 3.3.1-1, Note 1), uses the same inputs, equation and constants used in the CTS with the following differences:

a. ITS 3.3.1, Function 5 (and associated acceptance criteria in Table 3.3.1-1, Note 1), uses an "Allowable Value" (i.e., as-found setpoint) as the Limiting Safety System Setting (See ITS 3.3.1, DOC L.1).

b. ITS 3.3.1, Function 5, acceptance criteria in Note 1 are modified to explicitly require that Laplace transform operators that model system response and the associated Tau values, the electronic dynamic compensation time constants, are set at the required values. Inclusion of this acceptance criteria in the ITS is an administrative change with no impact on safety because this acceptance criteria is consistent with current analysis assumptions and procedural requirements.

Justification for Change

Indian Point 2 is currently in the process of developing an allowable value of this function using a methodology consistent with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation." When completed, Indian Point 2 will submit to the NRC a copy of site specific methodology and the results. Upon NRC approval, the allowable values will be incorporated into the Improved Technical Specification submittal.

Use of "Allowable Values" (i.e., as-found setpoints) as the LSSS is a less restrictive change. These changes are described and justified in ITS 3.3.1, DOC L.1.

A.09.f **3.3.1: Reactor Protection System (RPS) Instrumentation**

Rev. 1

Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.1, Function 6, Overpower delta T.

Description of Change

CTS 2.3.1.B(5) establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the Overpower delta T function based on a calculation that includes input from RCS Temperature as described in CTS 2.3.1.B(5). This nominal trip setpoint was established based on Indian Point Nuclear Generating Station Unit No. 2 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, and is considered conservative.

ITS 3.3.1, Function 6 (and associated acceptance criteria in Table 3.3.1-1, Note 2), uses the same equation and constants used in the CTS with the following difference. ITS 3.3.1, Function 6 (and associated acceptance criteria in Table 3.3.1-1, Note 2), uses an "Allowable Value" (i.e., as-found setpoint) as the Limiting Safety System Setting. Additionally, ITS replaces the differential used to denote the rate of change of temperature with respect to time with the more commonly used Laplace transform.

Justification for Change

Indian Point 2 is currently in the process of developing an allowable value of this function using a methodology consistent with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation." When completed, Indian Point 2 will submit to the NRC a copy of site specific methodology and the results. Upon NRC approval, the allowable values will be incorporated into the Improved Technical Specification submittal.

Use of "Allowable Values" (i.e., as-found setpoints) as the LSSS is a less restrictive change. These changes are described and justified in ITS 3.3.1, DOC L.1.

A.10 **3.3.1: Reactor Protection System (RPS) Instrumentation**

Rev. 1

Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of requirements for:
ITS 3.3.1, Function 7.a, Pressurizer Pressure-Low.

Description of Change

ITS 3.3.1, Function 7.a, Pressurizer Pressure-Low, is equivalent to CTS 2.3.1.B(3), CTS Table 3.5-2, Function 7, Low Pressurizer Pressure, and CTS Table 4.1-1, Item 7.

Justification for Change

This is an administrative change with no impact on safety because there are no changes to the existing requirements except as described and justified in the following sections:
a) describes changes in Applicability requirements;
b) describes changes in requirements for number of Operable channels;
c) describes changes to Required Actions for one inoperable channel;
d) describes changes for Required Actions for loss of function or extended loss of redundancy;
e) describes changes for Surveillance requirements; and,
f) describes changes for Allowable Values and Setpoints.
These descriptions reference discussions of change that justify any more or less restrictive changes that are described.

A.10.f 3.3.1: Reactor Protection System (RPS) Instrumentation

Rev. 1 Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.1, Function 7.a, Pressurizer Pressure-Low.

Description of Change

CTS 2.3.1.B (3) establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the Low Pressurizer Pressure function at greater than or equal to 1928 psig. This nominal trip setpoint was established based on Indian Point Nuclear Generating Station Unit No. 2 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, and is considered conservative.

ITS 3.3.1, Function 7.a, Pressurizer Pressure-Low, uses an "Allowable Value" (i.e., as-found setpoint) as the Limiting Safety System Setting.

Justification for Change

Indian Point 2 is currently in the process of developing an allowable value of this function using a methodology consistent with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation." When completed, Indian Point 2 will submit to the NRC a copy of site specific methodology and the results. Upon NRC approval, the allowable values will be incorporated into the Improved Technical Specification submittal.

Use of "Allowable Values" (i.e., as-found setpoints) as the LSSS is a less restrictive change. These changes are described and justified in ITS 3.3.1, DOC L.1.

A.11 3.3.1: Reactor Protection System (RPS) Instrumentation

Rev. 1 Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of requirements for:
ITS 3.3.1, Function 7.b, Pressurizer Pressure-High.

Description of Change

ITS 3.3.1, Function 7.b, Pressurizer Pressure-High, is equivalent to CTS 2.3.1.B(2), CTS Table 3.5-2, Function 8, High Pressurizer Pressure, and CTS Table 4.1-1, Item 7.

Justification for Change

This is an administrative change with no impact on safety because there are no changes to the existing requirements except as described and justified in the following sections:
a) describes changes in Applicability requirements;
b) describes changes in requirements for number of Operable channels;
c) describes changes to Required Actions for one inoperable channel;
d) describes changes for Required Actions for loss of function or extended loss of redundancy;
e) describes changes for Surveillance requirements; and,
f) describes changes for Allowable Values and Setpoints.
These descriptions reference discussions of change that justify any more or less restrictive changes that are described.

A.11.f 3.3.1: Reactor Protection System (RPS) Instrumentation

Rev. 1

Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.1, Function 7.b, Pressurizer Pressure-High.

Description of Change

CTS 2.3.1.B (2) establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the Low Pressurizer Pressure function at less than or equal to 2363 psig. This nominal trip setpoint was established based on Indian Point Nuclear Generating Station Unit No. 2 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, and is considered conservative.

ITS 3.3.1, Function 7.b, Pressurizer Pressure-High, uses an "Allowable Value" (i.e., as-found setpoint) as the Limiting Safety System Setting.

Justification for Change

Indian Point 2 is currently in the process of developing an allowable value of this function using a methodology consistent with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation." When completed, Indian Point 2 will submit to the NRC a copy of site specific methodology and the results. Upon NRC approval, the allowable values will be incorporated into the Improved Technical Specification submittal.

Use of "Allowable Values" (i.e., as-found setpoints) as the LSSS is a less restrictive change. These changes are described and justified in ITS 3.3.1, DOC L.1.

A.12 3.3.1: Reactor Protection System (RPS) Instrumentation

Rev. 1

Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of requirements for:
ITS 3.3.1, Function 8, Pressurizer Water Level-High.

Description of Change

ITS 3.3.1, Function 8, Pressurizer Water Level-High, is equivalent to CTS 2.3.1.C (1), CTS Table 3.5-2, Function 9, Pressurizer High Water Level, and CTS Table 4.1-1, Item 6.

Justification for Change

This is an administrative change with no impact on safety because there are no changes to the existing requirements except as described and justified in the following sections:
a) describes changes in Applicability requirements;
b) describes changes in requirements for number of Operable channels;
c) describes changes to Required Actions for one inoperable channel;
d) describes changes for Required Actions for loss of function or extended loss of redundancy;
e) describes changes for Surveillance requirements; and,
f) describes changes for Allowable Values and Setpoints.
These descriptions reference discussions of change that justify any more or less restrictive changes that are described.

A.12.f **3.3.1: Reactor Protection System (RPS) Instrumentation**
Rev. 1

Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.1, Function 8, Pressurizer Water Level-High.

Description of Change

CTS 2.3.1.C (1) establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the Pressurizer High Water Level function at greater than or equal to 90% of span. This nominal trip setpoint was established based on Indian Point Nuclear Generating Station Unit No. 2 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, and is considered conservative.

ITS 3.3.1, Function 8, Pressurizer Water Level-High, uses an "Allowable Value" (i.e., as-found setpoint) as the Limiting Safety System Setting.

Justification for Change

Indian Point 2 is currently in the process of developing an allowable value of this function using a methodology consistent with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation." When completed, Indian Point 2 will submit to the NRC a copy of site specific methodology and the results. Upon NRC approval, the allowable values will be incorporated into the Improved Technical Specification submittal.

Use of "Allowable Values" (i.e., as-found setpoints) as the LSSS is a less restrictive change. These changes are described and justified in ITS 3.3.1, DOC L.1.

A.13.f 3.3.1: Reactor Protection System (RPS) Instrumentation

Rev. 1

Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.1, Function 9, Reactor Coolant Flow-Low.

Description of Change

CTS 2.3.1.B (6) establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the Reactor Coolant Flow-Low function at greater than or equal to 92% of normal indicated loop flow. This nominal trip setpoint was established based on Indian Point Nuclear Generating Station Unit No. 2 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, and is considered conservative.

ITS 3.3.1, Function 9, Reactor Coolant Flow - Low, uses an "Allowable Value" (i.e., as-found setpoint) as the Limiting Safety System Setting.

Justification for Change

Indian Point 2 is currently in the process of developing an allowable value of this function using a methodology consistent with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation." When completed, Indian Point 2 will submit to the NRC a copy of site specific methodology and the results. Upon NRC approval, the allowable values will be incorporated into the Improved Technical Specification submittal.

Use of "Allowable Values" (i.e., as-found setpoints) as the LSSS is a less restrictive change. These changes are described and justified in ITS 3.3.1, DOC L.1.

A.16.e 3.3.1: Reactor Protection System (RPS) Instrumentation

Rev. 1

Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Surveillance requirements for:
ITS 3.3.1, Function 11, RCP Undervoltage (6.9 kV bus).

Description of Change

CTS Table 4.1-1, Item 8.a, requires a channel test every quarter; ITS SR 3.3.1.9 maintains the requirement to perform a Trip Actuating Device Operational Test (TADOT) at a Frequency of 92 days. ITS SR 3.3.1.9 is modified by a Note that provides an exception to the definition of a TADOT that is needed because setpoint verification for undervoltage and underfrequency relays requires elaborate bench calibration and is accomplished during the channel calibration.

CTS Table 4.1-1, Item 8.a, requires a channel calibration of the undervoltage relay every 24 months; ITS SR 3.3.1.10 maintains the requirement to perform a Channel Calibration at a Frequency of 24 months.

Justification for Change

This is an administrative change with no impact on safety because there is no change to the existing requirements.

A.16.f 3.3.1: Reactor Protection System (RPS) Instrumentation

Rev. 1

Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.1, Function 11, RCP Undervoltage (6.9 kV bus).

Description of Change

CTS 2.3.1.B (7) establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the RCP Undervoltage (6.9 kV bus) function at greater than or equal to 70% of normal voltage. This nominal trip setpoint was established based on Indian Point Nuclear Generating Station Unit No. 2 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, and is considered conservative.

ITS 3.3.1, Function 11, RCP Undervoltage (6.9 kV bus), uses an "Allowable Value" (i.e., as-found setpoint) as the Limiting Safety System Setting.

Justification for Change

Indian Point 2 is currently in the process of developing an allowable value of this function using a methodology consistent with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation." When completed, Indian Point 2 will submit to the NRC a copy of site specific methodology and the results. Upon NRC approval, the allowable values will be incorporated into the Improved Technical Specification submittal.

Use of "Allowable Values" (i.e., as-found setpoints) as the LSSS is a less restrictive change. These changes are described and justified in ITS 3.3.1, DOC L.1.

A.17.f ~~3.3.1: Reactor Protection System (RPS) Instrumentation~~

Rev. 1

~~Category Administrative: No Technical Changes~~

~~DOC Summary:~~

~~Adopts ITS presentation and organization of Allowable Values and Setpoints for:~~
~~ITS 3.3.1, Function 12, RCP Underfrequency (6.9 kV bus).~~

~~Description of Change~~

~~CTS 2.3.1.B (6) establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the Reactor Coolant Pump low frequency function at greater than or equal to 57.5 cycles per second (i.e., hertz). This nominal trip setpoint was established based on Indian Point Nuclear Generating Station Unit No. 2 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, and is considered conservative.~~

~~ITS 3.3.1, Function 9, Reactor Coolant Flow - Low, uses an "Allowable Value" (i.e., as-found setpoint) as the Limiting Safety System Setting.~~

~~Justification for Change~~

~~Indian Point 2 is currently in the process of developing an allowable value of this function using a methodology consistent with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation." When completed, Indian Point 2 will submit to the NRC a copy of site specific methodology and the results. Upon NRC approval, the allowable values will be incorporated into the Improved Technical Specification submittal.~~

~~Use of "Allowable Values" (i.e., as-found setpoints) as the LSSS is a less restrictive change. These changes are described and justified in ITS 3.3.1, DOC L.1.~~

A.18 3.3.1: Reactor Protection System (RPS) Instrumentation

Rev. 1

Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of requirements for:
ITS 3.3.1, Function 13, Steam Generator (SG) Water Level low-low.

Description of Change

ITS 3.3.1, Function 13, Steam Generator (SG) Water Level low-low, is equivalent to CTS 2.3.1.C (2), CTS Table 3.5-2, Function 11, Lo Lo Steam Generator Water Level, and CTS Table 4.1-1, Item 11.

Justification for Change

This is an administrative change with no impact on safety because there are no changes to the existing requirements except as described and justified in the following sections:
a) describes changes in Applicability requirements;
b) describes changes in requirements for number of Operable channels;
c) describes changes to Required Actions for one inoperable channel;
d) describes changes for Required Actions for loss of function or extended loss of redundancy;
e) describes changes for Surveillance requirements; and,
f) describes changes for Allowable Values and Setpoints.
These descriptions reference discussions of change that justify any more or less restrictive changes that are described.

A.18.f 3.3.1: Reactor Protection System (RPS) Instrumentation

Rev. 1

Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.1, Function 13, Steam Generator (SG) Water Level low-low.

Description of Change

CTS 2.3.1.C (2) establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the steam generator water level low-low function at greater than or equal to 7% of the narrow range instrument span. This nominal trip setpoint was established based on Indian Point Nuclear Generating Station Unit No. 2 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, and is considered conservative.

ITS 3.3.1, Function 13, Steam Generator (SG) Water Level low-low, uses an "Allowable Value" (i.e., as-found setpoint) as the Limiting Safety System Setting.

Justification for Change

Indian Point 2 is currently in the process of developing an allowable value of this function using a methodology consistent with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation." When completed, Indian Point 2 will submit to the NRC a copy of site specific methodology and the results. Upon NRC approval, the allowable values will be incorporated into the Improved Technical Specification submittal.

Use of "Allowable Values" (i.e., as-found setpoints) as the LSSS is a less restrictive change. These changes are described and justified in ITS 3.3.1, DOC L.1.

A.20.f 3.3.1: Reactor Protection System (RPS) Instrumentation

Rev. 1

Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.1, Function 15, Turbine Trip-Low Auto Stop Oil Pressure.

Description of Change

CTS does not establish any trip setpoint limiting safety system setting (allowable value) for the Turbine Trip-Low Auto Stop Oil Pressure. However, the calibration procedure ensures that the setpoint is below the minimum turbine control oil pressure that will allow the turbine to Operate.

ITS 3.3.1, Function 15, Turbine Trip-Low Auto Stop Oil Pressure, uses an "Allowable Value" (i.e., as-found setpoint) as the Limiting Safety System Setting.

Justification for Change

Indian Point 2 is currently in the process of developing an allowable value of this function using a methodology consistent with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation." When completed, Indian Point 2 will submit to the NRC a copy of site specific methodology and the results. Upon NRC approval, the allowable values will be incorporated into the Improved Technical Specification submittal.

Use of "Allowable Values" (i.e., as-found setpoints) as the LSSS is a less restrictive change. These changes are described and justified in ITS 3.3.1, DOC L.1.

A.21 3.3.1: Reactor Protection System (RPS) Instrumentation

Rev. 1

Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of requirements for:
ITS 3.3.1, Function 16, (Reactor Trip) Safety Injection (SI) Input from ESFAS.

Description of Change

ITS 3.3.1, Function 16, (Reactor Trip) Safety Injection (SI) Input from ESFAS, is equivalent to CTS Table 3.5-3, Function 6, Engineered Safety Features (SI) Logic (i.e., a reactor trip is generated by any safety injection signal) and CTS 4.5.A.1 which requires periodic verification that safety injection signals actuates the required components. (CTS Table 3.5-3, Function 6, was listed as CTS Table 3.5-2, Function 18.a, Engineered Safety Features (SI) Logic, on CTS Amendment 198 and was moved from CTS Table 3.5-2, Reactor Trip Instrumentation Limiting Operating Condition, to CTS Table 3.5-3, Instrumentation Operating Conditions for Engineered Safety Features, by CTS Amendment 212, dated November 30, 2000. See DOC M.13).

Justification for Change

This is an administrative change with no impact on safety because there are no changes to the existing requirements except as described and justified in the following sections:
a) describes changes in Applicability requirements;
b) describes changes in requirements for number of Operable channels;
c) describes changes to Required Actions for one inoperable channel;
d) describes changes for Required Actions for loss of function or extended loss of redundancy;
e) describes changes for Surveillance requirements; and,
f) describes changes for Allowable Values and Setpoints.
These descriptions reference discussions of change that justify any more or less restrictive changes that are described.

A.24.e 3.3.1: Reactor Protection System (RPS) Instrumentation

Rev. 1

Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Surveillance requirements for:
ITS 3.3.1, Function 17.c, Power Range Neutron Flux (P-8) Interlock.

Description of Change

ITS SR 3.3.1.11 and ITS SR 3.3.1.13 are added to require periodic Channel Operation Test and Channel Calibrations for this interlock

Justification for Change

The inclusion of ITS 3.3.1, Function 17.c, Power Range Neutron Flux (P-8) Interlock, in the ITS is a more restrictive change and is justified in DOC M.10.

A.24.f 3.3.1: Reactor Protection System (RPS) Instrumentation

Rev. 1

Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.1, Function 17.c, Power Range Neutron Flux (P-8) Interlock.

Description of Change

ITS 3.3.1, Function 17.c, Power Range Neutron Flux (P-8) Interlock, will use an "Allowable Value" (i.e., as-found setpoint) as the Limiting Safety System Setting.

Justification for Change

Indian Point 2 is currently in the process of developing an allowable value of this function using a methodology consistent with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation." When completed, Indian Point 2 will submit to the NRC a copy of site specific methodology and the results. Upon NRC approval, the allowable values will be incorporated into the Improved Technical Specification submittal.

Use of "Allowable Values" (i.e., as-found setpoints) as the LSSS is a less restrictive change. These changes are described and justified in ITS 3.3.1, DOC L.1.

A.25.f 3.3.1: Reactor Protection System (RPS) Instrumentation

Rev. 1 **Category** Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.1, Function 17.d, Power Range Neutron Flux (P-10) Interlock.

Description of Change

ITS 3.3.1, Function 17.d, Power Range Neutron Flux (P-10) Interlock, will use an "Allowable Value" (i.e., as-found setpoint) as the Limiting Safety System Setting.

Justification for Change

Indian Point 2 is currently in the process of developing an allowable value of this function using a methodology consistent with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation." When completed, Indian Point 2 will submit to the NRC a copy of site specific methodology and the results. Upon NRC approval, the allowable values will be incorporated into the Improved Technical Specification submittal.

Use of "Allowable Values" (i.e., as-found setpoints) as the LSSS is a less restrictive change. These changes are described and justified in ITS 3.3.1, DOC L.1.

A.26.f <u>3.3.1: Reactor Protection System (RPS) Instrumentation</u>

Rev. 1 <u>Category</u> Administrative: No Technical Changes

<u>DOC Summary:</u>

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.1, Function 17.e, Turbine First Stage Pressure (P-7 Input) Interlock.

<u>Description of Change</u>

TS 3.3.1, Function 17.e, Turbine First Stage Pressure (P-7 Input) Interlock, will use an "Allowable Value" (i.e., as-found setpoint) as the Limiting Safety System Setting.

CTS 2.3.2.A.(2) specifies that Turbine First Stage Pressure (P-7 Input) interlock must enable the reactor trips on low pressurizer pressure, high pressurizer level, and low reactor coolant flow for two or more loops when Turbine first stage pressure >10% "of equivalent full load." Turbine First Stage Pressure (P-7 Input) function takes advantage of the fact that turbine first stage pressure tracks total turbine power output very closely. Unless steam is being dumped (e.g., SG safety valves, atmospheric dump valves, turbine bypass to the condenser), turbine power is an excellent proxy for reactor thermal power. Note, however, that Turbine First Stage Pressure (P-7 Input) is only one of two interlocks that enable the reactor protection system trips listed above at approximately 10% reactor power. The other interlock, P-10 which is also an input to P-7, uses power range neutron flux as the basis for enabling the reactor protection system trips listed above are enabled at approximately 10% reactor power.

ITS 3.3.1, Function 17.e, Turbine First Stage Pressure (P-7 Input), maintains the requirement in CTS 2.3.2.A.(2); however, ITS 3.3.1, Function 17.e, expresses the allowable value for this interlock as percent "turbine power" versus the use of percent "equivalent full load."

The combination of the function name, Turbine First Stage Pressure (P-7 Input), and the description "turbine power" or "equivalent full load" clear explain that allowable value must be established as a proxy for reactor thermal power and the descriptive terms are interchangeable.

<u>Justification for Change</u>

Indian Point 2 is currently in the process of developing an allowable value of this function using a methodology consistent with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation." When completed, Indian Point 2 will submit to the NRC a copy of site specific methodology and the results. Upon NRC approval, the allowable values will be incorporated into the Improved Technical Specification submittal.

Use of "Allowable Values" (i.e., as-found setpoints) as the LSSS is a less restrictive change. These changes are described and justified in ITS 3.3.1, DOC L.1.

L.01 3.3.1: Reactor Protection System (RPS) Instrumentation

Rev. 0 Category Less Restrictive:

DOC Summary:

Replaces the nominal trip setpoint limiting safety system setting (i.e., the as-left setpoint) for all of the Reactor Protections System functions with an "Allowable Value" that was calculated using a methodology consistent with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation."

Description of Change

CTS 2.3.1 establishes the nominal trip setpoint (i.e., the as-left setpoint) as the limiting safety system setting for each of the following:
ITS 3.3.1, Function 2.b, Power Range Neutron Flux-Low;
ITS 3.3.1, Function 5, Overtemperature delta T;
ITS 3.3.1, Function 6, Overpower delta T;
ITS 3.3.1, Function 7.a, Pressurizer Pressure-Low;
ITS 3.3.1, Function 7.b, Pressurizer Pressure-High;
ITS 3.3.1, Function 8, Pressurizer Water Level-High;
ITS 3.3.1, Function 9, Reactor Coolant Flow-Low;
ITS 3.3.1, Function 11, RCP Undervoltage (6.9 kV bus);
ITS 3.3.1, Function 12, RCP Underfrequency (6.9 kV bus);
ITS 3.3.1, Function 13, Steam Generator (SG) Water Level low-low; and
associated interlocks for P-6, P-7, P-8, P-10 and Turbine first Stage pressure.

These nominal trip setpoints were established based on Indian Point Nuclear Generating Station Unit No.2 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, and are considered conservative.

ITS 3.3.1 replaces each of these nominal setpoints with an "Allowable Value" that was calculated using a methodology consistent with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation."

Justification for Change

Indian Point 2 is currently in the process of developing an allowable value of this function using a methodology consistent with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation." When completed, Indian Point 2 will submit to the NRC a copy of site specific methodology and the results. Upon NRC approval, the allowable values will be incorporated into the Improved Technical Specification submittal.

This change is needed because the limiting safety system settings established by IP2 Plant Manual, Volume VI, were based on information available at the time regarding instrument performance and methods available at the time for calculating setpoints. This change is acceptable because the allowable values calculated in accordance with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation" will ensure that sufficient allowance exists between this actual setpoint and the analytical limit to account for known instrument uncertainties. For example these may include design basis accident temperature and radiation effects or process dependent effects. This will provide assurance that the analytical limit will not be exceeded if the allowable value is satisfied. This change has no significant adverse impact on safety because the existing limiting safety system setting and the proposed allowable values used the information and methods available at the time to determine instrument settings that ensure that safety limits are not exceeded during any event.

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
	G.2.1	Be in MODE 3.	30 hours
	AND		
	G.2.2	Be in MODE 4.	36 hours
H. Main Boiler Feedwater Pump trip channel(s) inoperable.	H.1	Verify one channel associated with an operating MBFP is OPERABLE.	~~1 hour~~ Immediately
	AND		
	H.2	Restore one channel associated with each operating MBFP to OPERABLE status.	48 hours
I. Required Action and associated Completion Time of Condition H not met.	I.1	Be in MODE 3.	6 hours
J. One or more channels inoperable.	J.1	Verify interlock is in required state for existing unit condition.	1 hour
	OR		
	J.2.1	Be in MODE 3.	7 hours
	AND		
	J.2.2	Be in MODE 4.	13 hours

Table 3.3.2-1 (page 4 of 4)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
5. Feedwater Isolation					
a. Automatic Actuation Logic and Actuation Relays	1, 2[d], 3[d]	2 trains	G	SR 3.3.2.2 SR 3.3.2.3 SR 3.3.2.5	NA
b. SG Water Level - High High	1, 2[d], 3[d]	3 per SG	D	SR 3.3.2.4 SR 3.3.2.1 SR 3.3.2.7	≤ 77.7% NR
c. Safety Injection	[d] Refer to Function 1 (Safety Injection) for all initiation functions and requirements.				
6. Auxiliary Feedwater					
a. Automatic Actuation Logic and Actuation Relays	1,2,3	2 trains	G	SR 3.3.2.2 SR 3.3.2.3 SR 3.3.2.5	NA
b. SG Water Level - Low Low	1,2,3	3 per SG	D	SR 3.3.2.1 SR 3.3.2.7 SR3.3.24	≥ 3.7% NR
c. Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.				
d. Station Blackout (SBO) (Undervoltage Bus 5A or 6A)	1,2,3	Refer to LCO 3.3.5, "LOP DG Start Instrumentation," for requirements.			
e. Trip of Main Boiler Feedwater Pump	1[e], 2[e]	1 per MBFP	H	SR 3.3.2.6 SR 3.3.2.7	≥ 19.5 psig
7. ESFAS Interlocks Pressurizer Pressure	1,2,3	3	J	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≤ 1980 psig

(d) Except when the main feedwater flowpath to each SG is isolated by a closed and deactivated automatic valve or a closed manual valve.

(e) Only required for MBFPs that are in operation.

and provided the trip setpoint "as-left" value
i.e. in response to plant conditions.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Insert from 1st paragraph of page 6 of NUREG M/U.

steam line breaks (SLBs) outside containment. Functions such as manual initiation, not specifically credited in the accident safety analysis, are qualitatively credited in the safety analysis and the NRC staff approved licensing basis for the unit. These Functions may provide protection for conditions that do not require dynamic transient analysis to demonstrate Function performance. These Functions may also serve as backups to Functions that were credited in the accident analysis (Ref. 3).

The LCO requires all instrumentation performing an ESFAS Function identified in Table 3.3.2-1 to be OPERABLE. A channel is OPERABLE with a trip setpoint value outside its calibration tolerance band provided the trip setpoint "as-found" value does not exceed its associated Allowable Value. Failure of any instrument renders the affected channel(s) inoperable and reduces the reliability of the affected Functions.

The LCO generally requires OPERABILITY of four or three channels in each instrumentation function and two channels in each logic and manual initiation function. The two-out-of-three and the two-out-of-four configurations allow one channel to be tripped during maintenance or testing without causing an ESFAS initiation. Two logic or manual initiation channels are required to ensure no single random failure disables the ESFAS.

The required channels of ESFAS instrumentation provide unit protection in the event of any of the analyzed accidents. ESFAS protection functions are as follows:

1. <u>Safety Injection</u>

   Safety Injection (SI) provides two primary functions necessary to mitigate the effects of high energy line breaks (HELBs) both inside and outside of containment:

   1. Primary side water addition to ensure maintenance or recovery of reactor vessel water level (coverage of the active fuel for heat removal, clad integrity, and for limiting peak clad temperature to < 2200°F), and

   2. Boration to ensure recovery and maintenance of SDM (k_{eff} < 1.0).

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

2. <u>Containment Spray</u>

two

Containment Spray provides ~~three~~ primary functions;

1. Lowers containment pressure and temperature after a~~n~~ HELB in containment, and

2. Reduces the amount of radioactive iodine in the containment atmosphere.

These functions are necessary to:

- Ensure the pressure boundary integrity of the containment structure, and

- Limit the release of radioactive iodine to the environment in the event of a failure of the containment structure.

The containment spray actuation signal starts the containment spray pump associated with that logic train and aligns the discharge of the pumps to the containment spray nozzle headers in the upper levels of containment. Water is initially drawn from the RWST by the containment spray pumps. When the RWST reaches a specified minimum level, the spray pumps are manually secured. Recirculation or RHR pumps are used by diverting flow to the spray headers if continued containment spray is required. Containment spray is actuated manually or by Containment Pressure - High High.

a. <u>Containment Spray - Manual Initiation</u>

The operator can initiate containment spray at any time from the control room. Manual initiation of containment spray (CS) requires that either of two pushbuttons in the control room be depressed. Each pushbutton will actuate one logic train and the associated CS train. Two trains are required to be Operable (one pushbutton associated with each logic train).

Note that Manual Initiation of containment spray also actuates Phase B containment isolation and containment purge and exhaust line isolation and pressure relief line isolation.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Spray. When the two CS pushbuttons are depressed simultaneously, Phase B Containment Isolation and Containment Spray will be actuated in both trains.

a. <u>Containment Isolation - Phase A Isolation</u>

(1) <u>Phase A Isolation - Manual Initiation</u>

Manual Phase A Containment Isolation is actuated by either of two pushbuttons in the control room. Each pushbutton actuates one logic train. Note that manual initiation of Phase A Containment Isolation also actuates isolation of Containment Purge and Exhaust and the Containment Pressure relief line.

(2) <u>Phase A Isolation - Automatic Actuation Logic and Actuation Relays</u>

Automatic Actuation Logic and Actuation Relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

Manual and automatic initiation of Phase A Containment Isolation must be OPERABLE in MODES 1, 2, and 3, when there is a potential for an accident to occur. Manual initiation is also required in MODE 4 even though automatic actuation is not required. In this MODE, adequate time is available to manually actuate required components in the event of a DBA, but because of the large number of components actuated on a Phase A Containment Isolation, actuation is simplified by the use of the manual actuation push buttons. Automatic actuation logic and actuation relays must be OPERABLE in MODE 4 to support system level manual initiation. In MODES 5 and 6, there is insufficient energy in the primary or secondary systems to pressurize the containment to require Phase A Containment Isolation. There also is adequate time for the operator to evaluate unit conditions and manually actuate individual isolation valves in response to abnormal or accident conditions.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Feedwater Isolation Functions must be OPERABLE in MODES 1, 2 and 3 except when the main feedwater flowpath to each SG is isolated by a closed and deactivated automatic valve or a closed manual valve when the MFW System is in operation and the turbine generator may be in operation. In MODES 4, 5, and 6, the MFW System is not in service and this Function is not required to be OPERABLE.

6. Auxiliary Feedwater

The AFW System is designed to provide a secondary side heat sink for the reactor in the event that the MFW System is not available. The system has two motor driven pumps and a turbine driven pump. This ensures AFW is available during normal unit operation, during a loss of AC power and a loss of MFW. The normal source of water for the AFW System is the condensate storage tank (CST). The AFW System is aligned so that upon a motor driven pump start, flow is initiated to the respective SGs immediately.

a. Auxiliary Feedwater - Automatic Actuation Logic and Actuation Relays

Automatic actuation logic and actuation relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

b. Auxiliary Feedwater - Steam Generator Water Level - Low Low

A feedline break, inside or outside of containment, or a loss of MFW, would result in a loss of SG water level.

SG Water Level - Low Low provides protection against a loss of heat sink. Signals from two-out-of-three channels from any one SG will start the motor driven AFW pumps. Signals from two-out-of-three channels from any two SGs will start the steam driven AFW pump. The LCO requires three OPERABLE channels per steam generator.

With the transmitters (d/p cells) located inside containment and thus possibly experiencing adverse environmental conditions (feed line break), the Allowable Value reflects the inclusion of both steady state and adverse environmental instrument uncertainties.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

c. <u>Auxiliary Feedwater - Safety Injection</u>

An SI signal starts the motor driven AFW pumps. The AFW initiation functions are the same as the requirements for their SI function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 1, SI, is referenced for all initiating functions and requirements.

d. <u>Auxiliary Feedwater – Station Blackout (SBO) (Undervoltage Bus 5A or 6A)</u>

Replace with R3-S7 Insert B 3.3.2-29-03

The SBO Function that generates Auxiliary Feedwater system start signals uses the channels required to be OPERABLE by LCO 3.3.5, "Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation," Function c, including the differences in the actuation logic generated by a unit trip and the presence of an ESFAS safety injection signal. The SBO Function generates an automatic start signal for the turbine driven AFW pump if the undervoltage condition occurs in conjunction with a unit trip if no ESFAS safety injection signal is present. The SBO Function generates an automatic start signal for the motor driven AFW pumps if the undervoltage condition occurs in conjunction with a unit trip.

As described in the Bases of LCO 3.3.5, the SBO relays (i.e., channels) consist of two sets of three relays with one set associated with 480 V safeguards bus 5A (SBO train 5A) and the other set associated with safeguards bus 6A (SBO train 6A). If there is a loss of voltage on 480 V bus 5A or 6A, two out of the three SBO undervoltage relays associated with either bus 5A or 6A will actuate the undervoltage portion of the SBO function.

The requirements of the SBO function for the number of OPERABLE channels, the Required Actions when one or more channels are inoperable, Surveillance Testing of SBO channels, and the allowable values for LCO 3.3.2, Function 6.d, Auxiliary Feedwater SBO (Emergency Bus 5A or 6A) are the same as those required by LCO 3.3.5, "LOP DG Start Instrumentation." The requirement in LCO 3.3.5 to enter applicable Condition(s) and Required Action(s) for all DGs inoperable when there is a loss of the SBO function provides all required compensatory actions for loss of AFW automatic start on an undervoltage condition because AFW pumps can still be manually started and

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

loaded and automatic AFW start on SG low level and loss of feedwater are available. Additionally, LCO 3.3.2, Function 6.a, Auxiliary Feedwater - Automatic Actuation Logic and Actuation Relays, and LCO 3.7.5, Auxiliary Feedwater (AFW) System, establish Required Actions and Surveillance Testing for the Auxiliary Feedwater SBO (Emergency Bus 5A or 6A) function that are not addressed in LCO 3.3.5, "LOP DG Start Instrumentation." Therefore, LCO 3.3.2, Function 6.d, Auxiliary Feedwater SBO (Emergency Bus 5A or 6A) establishes requirements for the SBO function by referencing LCO 3.3.5 except for Applicability.

This function is needed because loss of offsite power to the 6.9 kV buses (and consequently the 480 V buses) will be accompanied by a loss of reactor coolant pumping power and the subsequent need for some method of decay heat removal.

Functions 6.a through 6.d must be OPERABLE in MODES 1, 2, and 3 to ensure that the SGs remain the heat sink for the reactor. SG Water Level - Low Low in any operating SG will cause the motor driven AFW pumps to start. The system is aligned so that upon a start of the pump, water immediately begins to flow to the SGs. SG Water Level - Low Low in any two operating SGs will cause the turbine driven pumps to start. These Functions do not have to be OPERABLE in MODES 5 and 6 because there is not enough heat being generated in the reactor to require the SGs as a heat sink. In MODE 4, AFW actuation does not need to be OPERABLE because either AFW or residual heat removal (RHR) will already be in operation to remove decay heat or sufficient time is available to manually place either system in operation.

e. Auxiliary Feedwater - Trip of Main Boiler Feedwater Pump

A Trip of either MBFP is an indication of a potential loss of MFW and the subsequent potential need for some method of decay heat and sensible heat removal to bring the reactor back to no load temperature and pressure. Each turbine driven MBFP is equipped with a pressure switch on the control oil line for the speed control system. A low pressure signal from this pressure switch indicates a trip of that pump. The single channel associated with each operating MBFP will start both motor driven AFW pumps. However, there is no single failure tolerance for this Function unless both MBFPs are operating. This is

immediate

BASES

ACTIONS (continued)

The single channel associated with each operating MBFP will start both motor driven AFW pumps if either MBFP trips. This ensures that AFW is started on a loss of main feedwater. However, there is no single failure tolerance for this Function unless both MBFPs are operating. Therefore, when a channel is inoperable, Required Action H.1 requires verification ~~within 1 hour~~ that a channel associated with an operating MBFP is OPERABLE to ensure that AFW will start automatically when there is a loss of main feedwater. Otherwise, Required Action I.1 requires that plant be in MODE 3 within the following 6 hours. The requirement for verification of the status of the channel associated with an operating MBFP may be completed by an administrative review. Actual testing is not required.

the

If both MBFPs are operating and there is an OPERABLE channel associated with only one operating pump, Required Action H.2 allows 48 hours to restore redundancy by requiring an OPERABLE channel for each operating MBFP. Otherwise, Required Action I.1 requires that the plant be in MODE 3 within the following 6 hours. Operating without redundant channels when only one MBFP is operating and operating for 48 hours when only one of the two MBFPs has an ~~operable~~ AFW starting channel is acceptable because this Function is a backup method for starting AFW and other Functions, in particular SG Water Level - Low Low, provide the primary protection against a loss of heat sink.

The Required Action I.1 Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging unit systems. In MODE 3, the unit does not have any analyzed transients or conditions that require the explicit use of the protection function noted above.

J.1, J.2.1 and J.2.2

Condition J applies to the Pressurizer Pressure interlock.

With one or more channels inoperable, the operator must verify that the interlock is in the required state for the existing unit condition. This action manually accomplishes the function of the interlock. Determination must be made within 1 hour. The 1 hour Completion Time is equal to the time allowed by LCO 3.0.3 to initiate shutdown actions in the event of a complete loss of ESFAS function. If the interlock is not in the required state (or placed in the required state) for the existing unit condition, the unit must be placed in MODE 3 within the next 6 hours and MODE 4 within the following 6 hours. The allowed Completion Times are reasonable, based on operating

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.2

SR 3.3.2.2 is the performance of an ACTUATION LOGIC TEST. The relay logic is tested every 92 days on a STAGGERED TEST BASIS. The train being tested is placed in the bypass condition, thus preventing inadvertent actuation. All possible logic combinations, with and without applicable permissives, are tested for each protection function. In addition, the master relay is tested. This verifies that the logic modules are OPERABLE and that there is a voltage signal path to the master relay coils. The Frequency of every 92 days on a STAGGERED TEST BASIS is justified in Reference 10.

SR 3.3.2.3

SR 3.3.2.3 is the performance of a MASTER RELAY TEST. The MASTER RELAY TEST is the energizing of the master relay, verifying contact operation and a low voltage continuity check of the slave relay coil. Upon master relay contact operation, a low voltage is supplied to the slave relay coil. This voltage is insufficient to pick up the slave relay, but large enough to demonstrate signal path continuity. This test is performed every 31 days on a STAGGERED TEST BASIS. The time allowed for the testing (8 hours) and the surveillance interval are justified in Reference 7.

SR 3.3.2.4

2

SR 3.3.2.4 is the performance of a COT. A COT is performed on each required channel to ensure the entire channel (except for the transmitter sensing device) will perform the intended Function. Setpoints must be found within calibration acceptance criteria consistent with the Allowable Values specified in Table 3.3.2-1. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL OPERATIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

The "as found" and "as left" values must also be recorded and reviewed for consistency with the assumptions of Reference 6 which incorporates the assumptions of Reference 7. The difference between the current "as found" values and the previous test "as left" values must be consistent with the drift allowance used in the setpoint methodology. The setpoint shall be left set consistent with the assumptions of the current unit specific setpoint methodology.

Add ITS 3.3.2, Function 5.b, SG Level - High High (A.25) - (M.8)

L.1 is removed

Table 3.5-1

Engineered Safety Features Initiation Instrument Setting Limits

	No.	Functional Unit	Channel	Setting Limits	
T3.3.2-1, #1.c	1.	High Containment Pressure (Hi Level)	Safety Injection	≤ 2.0 psig 8.6 ~~L.1~~	A.5
T3.3.2-1, #2.c 4.c 3.b.(3)	2.	High Containment Pressure (Hi-Hi Level)	a. Containment Spray b. Steam Line Isolation	≤ 20 psig 28.6 ~~L.1~~	A.12 A.21 A.18
T3.3.2-1, #1.d	3.	Pressurizer Low Pressure	Safety Injection	≥ 1833 psig 1801 ~~L.1~~	A.6
T3.3.2-1, #1.e	4.	High Differential Pressure Between Steam Lines	Safety Injection	≤ 55 psi 237.4 psid ~~L.1~~	A.7
T3.3.2-1, #1.f 1.g T3.3.2-1, #4.d 4.e	5.	High Steam Flow in 2/4 Steam Lines Coincident with Low Tavg or Low Steam Line Pressure	a. Safety Injection b. Steam Line Isolation	~~L.1~~ 53.7 1108 ≤ 40% of full steam flow at zero load ≤ 40% of full steam flow at 20% load ≤ 110% of full steam flow at full load ~~L.1~~ 540.75 425.0 ≥ 540°F Tavg ≥ 525 psig steam line pressure	A.8 A.9 A.22 A.23
T3.3.2-1, #6.b	6.	Steam Generator Water Level (Low-Low)	Auxiliary Feedwater	~~L.1~~ 3.7 ≥ 7% of narrow range instrument span each steam generator	A.28
T3.3.2-1, #6.d	7.	Station Blackout (Undervoltage)	Auxiliary Feedwater	~~L.1~~ 1986V ≥ 40% nominal voltage	A.30
SEE ITS 3.3.5	8a.	480V Emergency Bus Undervoltage (Loss of Voltage)	------	220V + 100V, -20V 3 sec ± 1 sec	
	8b.	480V Emergency Bus Undervoltage (Degraded Voltage)	------	421V ± 6V 180 sec ± 30 sec (no SI) 10 sec ± 2 sec (coincident	

Table

Minimum Frequencies for Checks, Calibrations and Tests of Instrument Channels

	Channel Description	Check	Calibrate	Test	Remarks	
SEE ITS 3.3.1	8.a 6.9 kV Voltage	N.A.	R#	Q		
	8.b 6.9 kV Frequency	N.A.	R#	Q (1) R# (2)	1) Underfrequency relay actuation only. 2) The full test including RCP breaker trip upon underfrequency relay actuation and reactor trip logic relay actuation upon tripping of the RCP breaker.	
SEE ITS 3.1.4, 3.1.5, 3.1.7	9. Analog Rod Position	S	R#	M		
	10. Rod Position Bank Counters	S	N.A.	N.A.	With analog rod position	
T 3.3.2-1 #6.b T 3.3.2-1 #5.b	11. Steam Generator Level	12 hr. S SR 3.3.2.1	24 Month# R# SR 3.3.2.7	184 days Q SR 3.3.2.4	L.6	A.25 A.28
SEE CTS RELOCATED	12. Charging Flow	N.A.	R#	N.A.		
	13. Residual Heat Removal Pump Flow	N.A.	R#	N.A.		
	14. Boric Acid Tank Level	W	R#	N.A.		
SEE ITS 3.5.4	15. Refueling Water Storage Tank Level	W	Q	N.A.		
	16. DELETED					
SEE RELOC. R.2	17. Volume Control Tank Level	N.A.	R##	N.A.	L.6	
	18a. Containment Pressure M.6	B	24 Month R# A.38	184 days Q	Wide Range	A.12 A.18 A.21
T 3.3.2-1 #1.c	18b. Containment Pressure	S SR 3.3.2.1	R# SR 3.3.2.7	Q SR 3.3.2.4	Narrow Range 184 L.6	A.5

ITS Package Revision

T 3.3.2-1, #2.C
#3.b(3)
#4.C

ITS 3.3.2

A.05.f Rev. 1

3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation

Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.2, Function 1.c, Safety Injection-Containment Pressure-High.

Description of Change

CTS Table 3.5-1, Function 1, establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the Containment Pressure-High function at less than or equal to 2.0 psig. This nominal trip setpoint was established based on Indian Point Nuclear Generating Station Unit No. 2 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, and is considered conservative.

ITS 3.3.2, Function 1.c, Safety Injection-Containment Pressure-High, uses an "Allowable Value" (i.e., as-found setpoint) as the Limiting Safety System Setting.

Justification for Change

Indian Point 2 is currently in the process of developing an allowable value of this function using a methodology consistent with Part 1 of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation." When completed, Indian Point 2 will submit to the NRC a copy of site specific methodology and the results, Upon NRC approval, the allowable values will be incorporated into the Improved Technical Specification submittal.

Use of "Allowable Values" (i.e., as-found setpoints) as the LSSS is considered a less restrictive change. These changes are described and justified in ITS 3.3.2, DOC L.1.

A.06 Rev. 1

3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation

Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of requirements for:
ITS 3.3.2, Function 1.d, Safety Injection - Pressurizer Pressure - Low

Description of Change

ITS 3.3.2, Function 1.d, Safety Injection - Pressurizer Pressure - Low, is equivalent to CTS Table 3.5-1, Item 3, CTS Table 3.5-3, Item 1.d. (Safety Injection) Pressurizer Low Pressure), and CTS Table 4.1-1, Item 7.

Justification for Change

This is an administrative change with no impact on safety because there are no changes to the existing requirements except as described and justified in the following sections:
a) describes changes in Applicability requirements;
b) describes changes in requirements for number of Operable channels;
c) describes changes to Required Actions for one inoperable channel;
d) describes changes for Required Actions for loss of function or extended loss of redundancy;
e) describes changes for Surveillance requirements; and,
f) describes changes for Allowable Values and Setpoints.
These descriptions reference discussions of change that justify any more or less restrictive changes that are described.

A.06.f **3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation**

Rev. 1

Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.2, Function 1.d, Safety Injection - Pressurizer Pressure - Low

Description of Change

CTS Table 3.5-1, Function 3, Pressurizer Pressure Low, establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the Pressurizer Pressure - Low functioh at greater than or equal to 1833 psig. This nominal trip setpoint was established based on Indian Point Nuclear Generating Station Unit No. 2 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, and is considered conservative.

ITS 3.3.2, Function 1.d, Safety Injection - Pressurizer Pressure - Low, uses an "Allowable Value" (i.e., as-found setpoint) as the Limiting Safety System Setting.

Justification for Change

Indian Point 2 is currently in the process of developing an allowable value of this function using a methodology consistent with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation." When completed, Indian Point 2 will submit to the NRC a copy of site specific methodology and the results. Upon NRC approval, the allowable values will be incorporated into the Improved Technical Specification submittal.

Use of "Allowable Values" (i.e., as-found setpoints) as the LSSS is considered a less restrictive change. These changes are described and justified in ITS 3.3.2, DOC L.1.

A.07 **3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation**

Rev. 1

Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of requirements for:
ITS 3.3.2, Function 1.e. Safety Injection-High Differential Pressure Between Steam Lines

Description of Change

ITS 3.3.2, Function 1.e. Safety Injection-High Differential Pressure Between Steam Lines, is equivalent to CTS Table 3.5-1, Item 4, CTS Table 3.5-3, Item 1.c (Safety Injection) High Differential Pressure Between Steam Lines, and CTS Table 4.1-1, Item 23.

Justification for Change

This is an administrative change with no impact on safety because there are no changes to the existing requirements except as described and justified in the following sections:
a) describes changes in Applicability requirements;
b) describes changes in requirements for number of Operable channels;
c) describes changes to Required Actions for one inoperable channel;
d) describes changes for Required Actions for loss of function or extended loss of redundancy;
e) describes changes for Surveillance requirements; and,
f) describes changes for Allowable Values and Setpoints.
These descriptions reference discussions of change that justify any more or less restrictive changes that are described.

A.07.f Rev. 1

3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation

Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.2, Function 1.e. Safety Injection-High Differential Pressure Between Steam Lines

Description of Change

CTS Table 3.5-1, Function 4, High Differential Pressure Between Steam Lines, establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the High Differential Pressure Between Steam Lines function at less than or equal to 155 psi (i.e., psid). This nominal trip setpoint was established based on Indian Point Nuclear Generating Station Unit No. 2 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, and is considered conservative.

ITS 3.3.2, Function 1.e. Safety Injection-High Differential Pressure Between Steam Lines, uses an "Allowable Value" (i.e., as-found setpoint) as the Limiting Safety System Setting.

Justification for Change

Indian Point 2 is currently in the process of developing an allowable value of this function using a methodology consistent with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation." When completed, Indian Point 2 will submit to the NRC a copy of site specific methodology and the results. Upon NRC approval, the allowable values will be incorporated into the Improved Technical Specification submittal.

Use of "Allowable Values" (i.e., as-found setpoints) as the LSSS is considered a less restrictive change. These changes are described and justified in ITS 3.3.2, DOC L.1.

A.08 Rev. 1

3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation

Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of requirements for:
ITS 3.3.2, Function 1.f. Safety Injection - High Steam Flow in Two Steam Lines Coincident with Tave - Low

Description of Change

ITS 3.3.2, Function 1.f, Safety Injection-High Steam Flow in Two Steam Lines Coincident with Tave-Low, is equivalent to CTS Table 3.5-1, Item 5, CTS Table 3.5-3, Item 1.e, (Safety Injection) High Steam Flow in 2/4 Steam Lines Coincident with Low Tave, CTS Table 4.1-1, Item 4 (Reactor Coolant Temperature), and CTS Table 4.1-1, Item 24 (turbine first stage pressure (i.e., input to the Steam Flow Setpoint Adjustment). Note that there is no explicit requirement in CTS Table 4.1-1 for testing the steam line flow function.

Justification for Change

This is an administrative change with no impact on safety because there are no changes to the existing requirements except as described and justified in the following sections:
a) describes changes in Applicability requirements;
b) describes changes in requirements for number of Operable channels;
c) describes changes to Required Actions for one inoperable channel;
d) describes changes for Required Actions for loss of function or extended loss of redundancy;
e) describes changes for Surveillance requirements; and,
f) describes changes for Allowable Values and Setpoints.
These descriptions reference discussions of change that justify any more or less restrictive changes that are described.

A.08.f ~~3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation~~

Rev. 1 ~~**Category** Administrative: No Technical Changes~~

~~**DOC Summary:**~~

~~Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.2, Function 1.f. Safety Injection - High Steam Flow in Two Steam Lines Coincident with Tave - Low~~

~~**Description of Change**~~

~~CTS Table 3.5-1, Item 5, Safety High Steam Flow in 2/4 Steam Lines Coincident with Low Tave or Low Steam Line Pressure, establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the High Steam Flow Coincident with Low Tave or Low Steam Line Pressure function. This setpoint changes based on input from the turbine first stage pressure. This nominal trip setpoint was established based on Indian Point Nuclear Generating Station Unit No. 2 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, and is considered conservative.~~

~~ITS 3.3.2, Functions 1.d, 1.e, 1.f, 4.d and 4.e, use an "Allowable Value" (i.e., as-found setpoint) as the Limiting Safety System Setting.~~

~~**Justification for Change**~~

~~Indian Point 2 is currently in the process of developing an allowable value of this function using a methodology consistent with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation." When completed, Indian Point 2 will submit to the NRC a copy of site specific methodology and the results. Upon NRC approval, the allowable values will be incorporated into the Improved Technical Specification submittal.~~

~~Use of "Allowable Values" (i.e., as-found setpoints) as the LSSS is considered a less restrictive change. These changes are described and justified in ITS 3.3.2, DOC L.1.~~

A.09.f **3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation**

Rev. 1

Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.2, Function 1.g. Safety Injection - High Steam Flow in Two Steam Lines Coincident with Steam Line Pressure - Low

Description of Change

CTS Table 3.5-1, Item 5, Safety High Steam Flow in 2/4 Steam Lines Coincident with Low Tave or Low Steam Line Pressure, establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the High Steam Flow Coincident with Low Tave or Low Steam Line Pressure function. This setpoint changes based on input form the turbine first stage pressure. This nominal trip setpoint was established based on Indian Point Nuclear Generating Station Unit No. 2 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, and is considered conservative.

ITS 3.3.2, Functions 1.d, 1.e, 1.g, 4.d and 4.e, use an "Allowable Value" (i.e., as-found setpoint) as the Limiting Safety System Setting.

Justification for Change

Indian Point 2 is currently in the process of developing an allowable value of this function using a methodology consistent with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation." When completed, Indian Point 2 will submit to the NRC a copy of site specific methodology and the results. Upon NRC approval, the allowable values will be incorporated into the Improved Technical Specification submittal.

Use of "Allowable Values" (i.e., as-found setpoints) as the LSSS is considered a less restrictive change. These changes are described and justified in ITS 3.3.2, DOC L.1.

A.10 **3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation**

Rev. 1

Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of requirements for:
ITS 3.3.2, Function 2.a. Containment Spray-Manual Initiation

Description of Change

ITS 3.3.2, Function 2.a. Containment Spray-Manual Initiation, is equivalent to CTS Table 3.5-3, Item 2.a. (Containment Spray) Manual.

Justification for Change

This is an administrative change with no impact on safety because there are no changes to the existing requirements except as described and justified in the following sections:
a) describes changes in Applicability requirements;
b) describes changes in requirements for number of Operable channels;
c) describes changes to Required Actions for one inoperable channel;
d) describes changes for Required Actions for loss of function or extended loss of redundancy;
e) describes changes for Surveillance requirements; and,
f) describes changes for Allowable Values and Setpoints.
These descriptions reference discussions of change that justify any more or less restrictive changes that are described.

A.12.f **3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation**

Rev. 1 **Category** Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.2, Function 2.c, Containment Spray - Containment Pressure (High-High)

Description of Change

CTS Table 3.5-1, Item 2, High Containment Pressure (Hi Hi Level), establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the Containment Pressure (High-High) function at less than or equal to 24 psig. This nominal trip setpoint was established based on Indian Point Nuclear Generating Station Unit No. 2 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, and is considered conservative.

ITS 3.3.2, Function 2.c, Containment Spray - Containment Pressure (High-High), uses an "Allowable Value" (i.e., as-found setpoint) as the Limiting Safety System Setting.

Justification for Change

Indian Point 2 is currently in the process of developing an allowable value of this function using a methodology consistent with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation." When completed, Indian Point 2 will submit to the NRC a copy of site specific methodology and the results. Upon NRC approval, the allowable values will be incorporated into the Improved Technical Specification submittal.

Use of "Allowable Values" (i.e., as-found setpoints) as the LSSS is considered a less restrictive change. These changes are described and justified in ITS 3.3.2, DOC L.1.

A.13 **3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation**

Rev. 1 **Category** Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of requirements for:
ITS 3.3.2, Function 3.a.(1), Containment Phase A Isolation-Manual Initiation

Description of Change

ITS 3.3.2, Function 3.a.(1), Containment Phase A Isolation-Manual Initiation, is equivalent to CTS Table 3.5-4, Item 1.c, (Containment Isolation - Phase A) Manual.

Justification for Change

This is an administrative change with no impact on safety because there are no changes to the existing requirements except as described and justified in the following sections:
a) describes changes in Applicability requirements;
b) describes changes in requirements for number of Operable channels;
c) describes changes to Required Actions for one inoperable channel;
d) describes changes for Required Actions for loss of function or extended loss of redundancy;
e) describes changes for Surveillance requirements; and,
f) describes changes for Allowable Values and Setpoints.
These descriptions reference discussions of change that justify any more or less restrictive changes that are described.

A.18.f 3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation

Rev. 1

Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.2, Function 3.b.(3), Containment Phase B Isolation-Containment Pressure (High-High)

Description of Change

CTS Table 3.5-1, Item 2, High Containment Pressure (Hi Hi Level), establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the Containment Pressure (High-High) function at less than or equal to 24 psig. This nominal trip setpoint was established based on Indian Point Nuclear Generating Station Unit No. 2 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, and is considered conservative.

ITS 3.3.2, Function 3.b.(3), Containment Phase B Isolation-Containment Pressure (High-High), uses an "Allowable Value" (i.e., as-found setpoint) as the Limiting Safety System Setting.

Justification for Change

Indian Point 2 is currently in the process of developing an allowable value of this function using a methodology consistent with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation." When completed, Indian Point 2 will submit to the NRC a copy of site specific methodology and the results. Upon NRC approval, the allowable values will be incorporated into the Improved Technical Specification submittal.

Use of "Allowable Values" (i.e., as-found setpoints) as the LSSS is considered a less restrictive change. These changes are described and justified in ITS 3.3.2, DOC L.1.

A.19 3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation

Rev. 1

Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of requirements for:
ITS 3.3.2, Function 4.a Steam Line Isolation-Manual Initiation

Description of Change

ITS 3.3.2, Function 4.a Steam Line Isolation-Manual Initiation, is equivalent to CTS Table 3.5-4, Item 2.c, (Steam Line Isolation) Manual.

Justification for Change

This is an administrative change with no impact on safety because there are no changes to the existing requirements except as described and justified in the following sections:
a) describes changes in Applicability requirements;
b) describes changes in requirements for number of Operable channels;
c) describes changes to Required Actions for one inoperable channel;
d) describes changes for Required Actions for loss of function or extended loss of redundancy;
e) describes changes for Surveillance requirements; and,
f) describes changes for Allowable Values and Setpoints.
These descriptions reference discussions of change that justify any more or less restrictive changes that are described.

A.21.f 3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation

Rev. 1

Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.2, Function 4.c, Steam Line Isolation - Containment Pressure (High-High)

Description of Change

CTS Table 3.5-1, Item 2, High Containment Pressure (Hi Hi Level), establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the Containment Pressure (High-High) function at less than or equal to 24 psig. This nominal trip setpoint was established based on Indian Point Nuclear Generating Station Unit No. 2 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, and is considered conservative.

ITS 3.3.2, Function 4.c, Steam Line Isolation - Containment Pressure (High-High), uses an "Allowable Value" (i.e., as-found setpoint) as the Limiting Safety System Setting.

Justification for Change

Indian Point 2 is currently in the process of developing an allowable value of this function using a methodology consistent with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation." When completed, Indian Point 2 will submit to the NRC a copy of site specific methodology and the results. Upon NRC approval, the allowable values will be incorporated into the Improved Technical Specification submittal.

Use of "Allowable Values" (i.e., as-found setpoints) as the LSSS is considered a less restrictive change. These changes are described and justified in ITS 3.3.2, DOC L.1.

A.22 3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation

Rev. 1

Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of requirements for:
ITS 3.3.2, Function 4.d. Steam Line Isolation - High Steam Flow in Two Steam Lines Coincident with Tave - Low

Description of Change

ITS 3.3.2, Function 4.d. Steam Line Isolation - High Steam Flow in Two Steam Lines Coincident with Tave - Low, is equivalent to CTS Table 3.5-1, Item 5, CTS Table 3.5-4, Item 2.a (Steam Line Isolation) High Steam Flow in 2/4 Steam Lines Coincident with Low Tave, CTS Table 4.1-1, Item 4 (reactor coolant temperature), CTS Table 4.1-1, Item 24 (turbine first stage pressure (i.e., input to the Steam Flow Setpoint Adjustment)). Note that there is no explicit requirement in CTS Table 4.1-1 for testing the steam line flow function.

Justification for Change

This is an administrative change with no impact on safety because there are no changes to the existing requirements except as described and justified in the following sections:
a) describes changes in Applicability requirements;
b) describes changes in requirements for number of Operable channels;
c) describes changes to Required Actions for one inoperable channel;
d) describes changes for Required Actions for loss of function or extended loss of redundancy;
e) describes changes for Surveillance requirements; and,
f) describes changes for Allowable Values and Setpoints.
These descriptions reference discussions of change that justify any more or less restrictive changes that are described.

A.22.f **3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation**

Rev. 1 **Category** Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.2, Function 4.d. Steam Line Isolation - High Steam Flow in Two Steam Lines Coincident with Tave - Low

Description of Change

CTS Table 3.5-1, Item 5, Safety High Steam Flow in 2/4 Steam Lines Coincident with Low Tave or Low Steam Line Pressure, establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the High Steam Flow Coincident with Low Tave or Low Steam Line Pressure function. This setpoint changes based on input form the turbine first stage pressure. This nominal trip setpoint was established based on Indian Point Nuclear Generating Station Unit No. 2 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, and is considered conservative.

ITS 3.3.2, Functions 1.d, 1.e, 4.d and 4.e use an "Allowable Value" (i.e., as-found setpoint) as the Limiting Safety System Setting.

Justification for Change

Indian Point 2 is currently in the process of developing an allowable value of this function using a methodology consistent with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation." When completed, Indian Point 2 will submit to the NRC a copy of site specific methodology and the results. Upon NRC approval, the allowable values will be incorporated into the Improved Technical Specification submittal.

Use of "Allowable Values" (i.e., as-found setpoints) as the LSSS is considered a less restrictive change. These changes are described and justified in ITS 3.3.2, DOC L.1.

A.23.f 3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation

Rev. 1

Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.2, Function 4.e. Steam Line Isolation - High Steam Flow in Two Steam Lines Coincident with Steam Line Pressure - Low

Description of Change

CTS Table 3.5-1, Item 5, Safety High Steam Flow in 2/4 Steam Lines Coincident with Low Tave or Low Steam Line Pressure, establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the High Steam Flow Coincident with Low Tave or Low Steam Line Pressure function. This setpoint changes based on input form the turbine first stage pressure. This nominal trip setpoint was established based on Indian Point Nuclear Generating Station Unit No. 2 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, and is considered conservative.

ITS 3.3.2, Functions 1.d, 1.e, 4.d and 4.e, use an "Allowable Value" (i.e., as-found setpoint) as the Limiting Safety System Setting.

Justification for Change

Indian Point 2 is currently in the process of developing an allowable value of this function using a methodology consistent with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation." When completed, Indian Point 2 will submit to the NRC a copy of site specific methodology and the results. Upon NRC approval, the allowable values will be incorporated into the Improved Technical Specification submittal.

Use of "Allowable Values" (i.e., as-found setpoints) as the LSSS is considered a less restrictive change. These changes are described and justified in ITS 3.3.2, DOC L.1.

A.25.f 3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation

Rev. 1

Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.2, Function 5.b, Feedwater Isolation - SG Level (High-High)

Description of Change

ITS 3.3.2, Function 5.b, Feedwater Isolation - SG Level (High-High), will use an "Allowable Value" (i.e., as-found setpoint) as the Limiting Safety System Setting.

Justification for Change

Adds requirement for Operability and Surveillance testing of ITS 3.3.2, Function 5.b, Feedwater Isolation - SG Water Level (High-High), because this Function is assumed to terminate an excessive heat removal due to feedwater system malfunction event in conjunction with reactor protection which is provided by overpower and overtemperature protection (high neutron flux, overtemperature delta T and overpower delta T trips).

Indian Point 2 is currently in the process of developing an allowable value of this function using a methodology consistent with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation." When completed, Indian Point 2 will submit to the NRC a copy of site specific methodology and the results. Upon NRC approval, the allowable values will be incorporated into the Improved Technical Specification submittal.

Use of "Allowable Values" (i.e., as-found setpoints) as the LSSS is considered a less restrictive change. These changes are described and justified in ITS 3.3.2, DOC L.1.

A.26 3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation

Rev. 1

Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of requirements for:
ITS 3.3.2, Function 5.c, Feedwater Isolation - Safety Injection

Description of Change

ITS 3.3.2, Function 5.c, Feedwater Isolation - Safety Injection, is equivalent to CTS Table 3.5-4, Item 3.a (Feedwater Line Isolation) Safety Injection. This Function consists of a contact that initiates Feedwater Isolation as result of a Safety Injection Signal. CTS Table 3.5-4, Item 3.a, references CTS Table 3.5-3, Item 1, (Safety Injection), for the CTS requirements for this Function.

ITS 3.3.2, Function 5.c, references ITS Function 1 (Safety Injection) for all requirements for this function. Just as in the CTS, this cross reference is appropriate because all requirements for inputs to ITS 3.3.2, Function 5.c, Feedwater Isolation - Safety Injection are appropriately addressed by Safety Injection requirements (ITS 3.3.2 Function 1) and all outputs are addressed by ITS 3.3.2, Function 5.a, Feedwater Isolation-Automatic Actuation Logic and Actuation Relays. Therefore, there are no changes to the existing CTS requirements except as identified and justified in DOCs A.3 through A.9 for changes to the Safety Injection Functions that initiate this Function and in DOC A.24 for the ITS 3.3.2, Function 5.a, Feedwater Isolation-Automatic Actuation Logic and Actuation Relays for this function.

Justification for Change

This is an administrative change with no impact on safety because there are no changes to the existing requirements.

A.28.e 3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation

Rev. 1

Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Surveillance requirements for:
ITS 3.3.2, Function 6.b, Auxiliary Feedwater - SG Water Level - low-low

Description of Change

CTS Table 4.1-1, Item 30.a, Auxiliary Feedwater - Steam Generator Level (low-low), requires a channel check every shift (i.e., 12 hours). ITS SR 3.3.2.1 requires a channel check every 12 hours which maintains the existing requirement and Frequency.

CTS Table 4.1-1, Item 30.a, Auxiliary Feedwater - Steam Generator Level (low-low), requires a channel calibration at interval R# (i.e., every 24 months). ITS SR 3.3.2.7 requires a channel calibration every 24 months which maintains the existing requirement and Frequency.

Justification for Change

This is an administrative change with no impact on safety because there is no change to the existing requirement.

A.28.f 3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation

Rev. 1

Category Administrative: No Technical Changes

DOC Summary:

~~Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.2, Function 6.b, Auxiliary Feedwater - SG Water Level - low-low~~

Description of Change

~~CTS Table 3.5-1, Item 6, establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the SG Water Level - low-low function at greater than or equal to 7% of the narrow range instrument span. This nominal trip setpoint was established based on Indian Point Nuclear Generating Station Unit No. 2 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, and is considered conservative.~~

~~ITS 3.3.2, Function 6.b, Auxiliary Feedwater - SG Water Level - low-low, uses an "Allowable Value" (i.e., as-found setpoint) as the Limiting Safety System Setting.~~

Justification for Change

~~Indian Point 2 is currently in the process of developing an allowable value of this function using a methodology consistent with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation." When completed, Indian Point 2 will submit to the NRC a copy of site specific methodology and the results. Upon NRC approval, the allowable values will be incorporated into the Improved Technical Specification submittal.~~

~~Use of "Allowable Values" (i.e., as-found setpoints) as the LSSS is considered a less restrictive change. These changes are described and justified in ITS 3.3.2, DOC L.1.~~

A.30.f Rev. 1 **3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation**

Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.2, Function 6.d. Auxiliary Feedwater-Station Blackout (SBO) (Undervoltage Bus 5A or 6A)

Description of Change

CTS Table 3.5-1, Item 7, Station Blackout (Undervoltage), establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for CTS Table 3.5-3, Item 4.c, (Auxiliary Feedwater) Station Blackout (Start Motor Driven and Steam Driven Pumps) at greater than or equal to 40% of nominal voltage (i.e., 40% of 480 V). This nominal trip setpoint was established based on Indian Point Nuclear Generating Station Unit No. 2 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, and is considered conservative.

LCO 3.3.2, Function 6.d, Auxiliary Feedwater SBO (Emergency Bus 5A or 6A) establishes requirements for the SBO function by referencing LCO 3.3.5 except for Applicability. The requirements for allowable values for LCO 3.3.2, Function 6.d, Auxiliary Feedwater SBO (Emergency Bus 5A or 6A) are the same as those required by LCO 3.3.5, "LOP DG Start Instrumentation." ITS 3.3.5, 480 V Bus Station Blackout (SBO) Function - LOP DG Start Instrumentation, uses an "Allowable Value" (i.e., as-found setpoint) as the Limiting Safety System Setting.

Justification for Change

Indian Point 2 is currently in the process of developing an allowable value of this function using a methodology consistent with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation." When completed, Indian Point 2 will submit to the NRC a copy of site specific methodology and the results. Upon NRC approval, the allowable values will be incorporated into the Improved Technical Specification submittal.

Use of "Allowable Values" (i.e., as-found setpoints) as the LSSS is considered a less restrictive change. These changes are described and justified in ITS 3.3.2, DOC L.1.

A.31.b <u>3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation</u>

Rev. 1

<u>Category</u> Administrative: No Technical Changes

<u>DOC Summary:</u>

Adopts ITS presentation of requirements for number of channels for:
ITS 3.3.2, Function 6.e. Auxiliary Feedwater - Trip of Main Boiler Feedwater Pump

<u>Description of Change</u>

CTS Table 3.5-3, Function 4.d, requires 1 operable channel with a minimum degree of redundancy of zero (See ITS 3.3.2, DOC A.37). The IP2 design is that a single channel associated with each operating MBFP will start both motor driven AFW pumps. CTS Table 3.5-3, Item 4.d, does not require any allowance for single failure.

ITS Function 6.e is revised to require 1 channel per operating main feed pump. Therefore, ITS 3.3.2, Function 6.e, is more restrictive (See 3.3.2, DOC M.9).

<u>Justification for Change</u>

Requiring two Operable channels (i.e., one Operable channel associated with each Operating feedwater pump) is a more restrictive change that is justified in DOC M.9.

A.31.c <u>3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation</u>

Rev. 1

<u>Category</u> Administrative: No Technical Changes

<u>DOC Summary:</u>

Adopts ITS presentation and organization of Required Actions for one inoperable channel for:
ITS 3.3.2, Function 6.e. Auxiliary Feedwater - Trip of Main Boiler Feedwater Pump

<u>Description of Change</u>

For a loss of redundancy for the Auxiliary Feedwater - Trip of Main Boiler Feedwater Pump, CTS does not specify any actions because CTS Table 3.5-3 only requires 1 operable channel with a minimum degree of redundancy of zero for this function (See 3.3.2, DOC M.9). immediately

In conjunction with the revised requirement for 1 channel per operating main feed pump, when MBFP trip channels are inoperable, Required Action H.1.~~1~~, verifies that one channel associated with an operating MBFP is OPERABLE to ensure that there is no loss of function. If both MBFPs are operating, Required Action H.2.1 allows 48 hours to restore redundancy by requiring one channel associated with each operating MBFP to be OPERABLE. Continued operation without redundant channels when only MBFP is operating is acceptable because this is a backup method for starting AFW and other Functions, in particular SG Water Level -low-low, provide the primary protection against a loss of heat sink.

The IP2 plant design for this Function is not addressed in WCAP-10271 even after requirements were revised to require 1 channel per operating main feed pump. However, the allowable out of service times and surveillance test intervals are more conservative than CTS requirements (See 3.3.2, DOC M.9), accident scenarios are protected by Functions addressed in WCAP-10271, and the requirements specified in ITS 3.3.2 are consistent with plant design as described in the UFSAR.

<u>Justification for Change</u>

The 48 hour allowable out of service time to restore an inoperable channel is acceptable based on current licensing basis. The IP2 plant design for this Function is not addressed in WCAP-10271 even after requirements were revised to require 1 channel per operating feedwater pump. However, the allowable out of service times and surveillance test intervals are more conservative than CTS requirements accident scenarios are protected by Functions addressed in WCAP-10271, and the requirements specified in ITS 3.3.2 are consistent with plant design as described in the UFSAR.

A.31.f 3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation

Rev. 1 **Category** Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.2, Function 6.e. Auxiliary Feedwater - Trip of Main Boiler Feedwater Pump

Description of Change

CTS does not identify a limiting safety system setting for this function. Each turbine driven MBFP is equipped with a pressure switch on the control oil line for the speed control system. A low pressure signal (i.e., essentially 0 psig) from this pressure switch indicates a trip of that pump.
ITS 3.3.2, Function 6.e. Auxiliary Feedwater - Trip of Main Boiler Feedwater Pump, will specify an "Allowable Value" (i.e., as-found setpoint) as the Limiting Safety System Setting for this function designed to ensure that calibration error and drift of the pressure switch do not allow the switch to be considered operable at 0 psig or below.

Justification for Change

Indian Point 2 is currently in the process of developing an allowable value of this function using a methodology consistent with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation." When completed, Indian Point 2 will submit to the NRC a copy of site specific methodology and the results. Upon NRC approval, the allowable values will be incorporated into the Improved Technical Specification submittal.

L.1 3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation

Rev. 0

Category Less Restrictive:

DOC Summary:

Replaces the nominal trip setpoint limiting safety system setting (i.e., the as-left setpoint) for all of the Engineered Safety Feature Actuation System (ESFAS) Instrumentation functions with an "Allowable Value" that was calculated using a methodology consistent with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation."

Description of Change

CTS Table 3.5-1 3.5 establishes the nominal trip setpoint (i.e., the as-left setpoint) as the limiting safety system setting for each of the ESFAS functions. These nominal trip setpoints were established based on Indian Point Nuclear Generating Station Unit No. 2 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, and are considered conservative.

ITS 3.3.2 replaces each of these nominal setpoints with an "Allowable Value" that was calculated using a methodology consistent with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation."

Justification for Change

Indian Point 2 is currently in the process of developing an allowable value of this function using a methodology consistent with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation." When completed, Indian Point 2 will submit to the NRC a copy of site specific methodology and the results. Upon NRC approval, the allowable values will be incorporated into the Improved Technical Specification submittal.

This change is needed because the limiting safety system settings established by IP2 Plant Manual, Volume VI, were based on information available at the time regarding instrument performance and methods available at the time for calculating setpoints. This change is acceptable because the allowable values calculated in accordance with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation" will ensure that sufficient allowance exists between this actual setpoint and the analytical limit to account for known instrument uncertainties. For example these may include design basis accident temperature and radiation effects or process dependent effects. This will provide assurance that the analytical limit will not be exceeded if the allowable value is satisfied. This change has no significant adverse impact on safety because the existing limiting safety system setting and the proposed allowable values used the information and methods available at the time to determine instrument settings that ensure that safety limits are not exceeded during any event.

L.2 3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation

Rev. 1

Category Less Restrictive:

DOC Summary:

Not Used.

Description of Change

Not Used.

Justification for Change

Not Used.

LA.2 **3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation**

Rev. 0

Category Relocated Detail:

DOC Summary:

Relocates requirement that the cover plate on the rear of the safeguards panel in the control room shall not be removed without authorization from the Watch Supervisor to a licensee document controlled by 10 CFR 50.59 (i.e., IP2 UFSAR 7.2.4.1.2)

Description of Change

CTS 3.5.5 requires that the cover plate on the rear of the safeguards panel in the control room shall not be removed without authorization from the Watch Supervisor. This requirement is relocated to UFSAR 7.2.4.1.2.

Justification for Change

This change is needed and is acceptable because the requirement that the cover plate on the rear of the safeguards panel in the control room shall not be removed without authorization from the Watch Supervisor is an engineering good practice and not an essential element for Operability of either RPS or ESFAS instrument systems.

LA.3 **3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation**

Rev. 1

Category Relocated Detail:

DOC Summary:

Relocates remarks and clarification notes that are not directly related to the Operability of any RPS or ESFAS Function to a licensee document controlled by 10 CFR 50.59 (i.e., ITS Bases)

Description of Change

CTS Table 4.1-1, Remarks Column, includes remarks and clarification notes that are not directly related to the Operability of any RPS or ESFAS Function. This information is relocated to the ITS Bases.

Justification for Change

This change is acceptable because ITS 3.3.1 and 3.3.2 establish clear requirements for the Operability and testing of each RPS and ESFAS Function in a format that does not require the use of these notes or qualifying remarks. Therefore, this information is incorporated into the Bases. This is acceptable because this information is incorporated into the minimum requirements and ITS specifies the minimum requirements for Operability and testing. Therefore, this information can be adequately defined and controlled in the ITS 3.3 Bases which require change control in accordance with ITS 5.5.13, Bases Control Program. This approach provides an effective level of regulatory control and provides for a more appropriate change control process. The level of safety of facility operation is unaffected by the change because there is no change in the requirement to maintain the instrumentation Operable. Furthermore, NRC and Indian Point 2 resources associated with processing license amendments to these requirements will be reduced. This change is a less restrictive administrative change with no impact on safety.

Need LA.4

BASES

APPLICABLE SAFETY ANALYSES (continued)

PAM instrumentation that meets the definition of Type A in Regulatory Guide 1.97 satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii). Category I, non-Type A, instrumentation must be retained in TS because it is intended to assist operators in minimizing the consequences of accidents. Therefore, Category I, non-Type A, variables are important for reducing public risk.

LCO

The PAM instrumentation LCO provides OPERABILITY requirements for Regulatory Guide 1.97 Type A monitors, which provide information required by the control room operators to perform certain manual actions specified in the unit Emergency Operating Procedures. These manual actions ensure that a system can accomplish its safety function, and are credited in the safety analyses. Additionally, this LCO addresses Regulatory Guide 1.97 instruments that have been designated Category I, non-Type A.

The OPERABILITY of the PAM instrumentation ensures there is sufficient information available on selected unit parameters to monitor and assess unit status following an accident. This capability is consistent with the recommendations of Reference 2.

LCO 3.3.3 requires at least two OPERABLE channels for most Functions. However, some functions, such as the RCS hot leg temperature and RCS cold leg temperature, require only one channel because they credit a required diverse function as a redundant channel. Two OPERABLE channels ensure no single failure prevents operators from getting the information necessary for them to determine the safety status of the unit, and to bring the unit to and maintain it in a safe condition following an accident.

Furthermore, OPERABILITY of two channels allows a CHANNEL CHECK during the post accident phase to confirm the validity of displayed information. More than two channels may be required for some functions if the IP2 Regulatory Guide 1.97 analyses (Ref. 4) determined that failure of one accident monitoring channel results in information ambiguity (that is, the redundant displays disagree) that could lead operators to defeat or fail to accomplish a required safety function.

4

Table 3.3.3-1 provides a list of variables typical of those identified by the IP2 Regulatory Guide 1.97 (Ref. 1) analyses. Table 3.3.3-1 includes all Type A and Category I variables identified by the unit specific Regulatory Guide 1.97 analyses, as amended by the NRC's SER (Ref. 1).

BASES

LCO (continued)

11. Pressurizer Level

Pressurizer Level is a Type A, Category I Function that is used to determine whether to terminate SI, if still in progress, or to reinitiate SI if it has been stopped. Knowledge of pressurizer water level is also used to verify the unit conditions necessary to establish natural circulation in the RCS and to verify that the unit is maintained in a safe shutdown condition.

This LCO is satisfied by the OPERABILITY of any two of the pressurizer level instruments designated LT-459, LT-460 and LT-461. Each channel has a range from the upper tap to the lower tap of the pressurizer which covers 85% of the pressurizer span.

12. Steam Generator Water Level (Narrow Range)

SG Water Level (narrow range) is a Type A, Category I Function. This Function is provided to monitor operation of decay heat removal via the SGs.

Each ~~Steam Generator (~~SG~~)~~ has three narrow range transmitters which span a range from the top of the tube bundles up to the moisture separator.

The LCO requirement for SG Level (narrow range) is satisfied by any two of the level instruments for each SG in the following list:

SG 21	SG 22	SG 23	SG 24
LT-417A	LT-427A	LT-437A	LT-447A
LT-417B	LT-427B	LT-437B	LT-447B
LT-417C	LT-427C	LT-437C	LT-447C

13. Steam Generator Water Level (Wide Range)

SG Water Level (wide range) is a Type B, Category I Function. Each ~~Steam Generator (~~SG~~)~~ has one wide range transmitter which spans a range from the tube sheet up to the moisture separator.

SG Water Level (Wide Range) is used to:

- identify the ruptured SG following a tube rupture,
- verify that the intact SGs are an adequate heat sink for the reactor,

BASES

LCO (continued)

15, 16, 17, 18. Core Exit Temperature

Core Exit Temperature is a Type A, Category III Function that is provided for verification and long term surveillance of core cooling.

Core exit temperature also serves as a redundant channel for the RCS Hot Leg Temperature (Function 1).

Core exit temperature is monitored by the core exit thermocouples (CETs). A total of 65 thermocouples are installed at preselected core locations to provide core exit temperature data up to 2300°F. There are two trains of CETs, one to process data for 34 thermocouples and the other for the remaining 31. The two trains receive power from redundant instrument busses. Two display units (one for each train) are provided on the central control room accident assessment panels. Each presents a graphic core location map with an alphanumeric display of core exit temperatures.

in

This LCO is satisfied by having 2 trains, each with a minimum of 2 qualified CETS (i.e., 4 CETs total) in each of the four quadrants. Requiring 2 qualified CETs each train in each of the four quadrants provides assurance that sufficient CETs are available to support evaluation of core radial decay power distribution. Each pairing of 2 CETs from the same train in each quadrant is considered a separate function.

19. Auxiliary Feedwater Flow

AFW Flow is a Type A, Category II Function that is provided to monitor operation of decay heat removal via the SGs.

AFW flow is used three ways: to verify delivery of AFW flow to the SGs if SG narrow range level indicators are off scale low; to determine whether to terminate SI if still in progress, in conjunction with SG water level (narrow range); and to regulate AFW flow so that the SG tubes remain covered.

The LCO requirement for AFW flow indication is satisfied by OPERABILITY of the following 4 flow transmitters:

SG 21	SG 22	SG 23	SG 24
FT-1200	FT-1201	FT-1202	FT-1203

subcooling margin monitor readout on the

BASES

LCO (continued)

Control room panel readout of the

Two channels are required to be Operable for redundancy. Alternate indication is available using saturation pressure and steam tables. The plant computer ~~subcooling margin readout~~ can be used as a substitute for the RCS Subcooling Margin Monitor.

22. Refueling Water Storage Tank (RWST) Level

RWST Level is a Type A, Category II Function that is used to confirm RWST level prior to the manual switchover to the cold leg recirculation phase that is initiated when the RWST level has reached the low low alarm setpoint and sufficient coolant inventory to support pump operation in recirculation mode is verified in the containment.

Two channels of RWST Level indication are required consistent with LCO 3.5.4, "Refueling Water Storage Tank" requirements for OPERABILITY of two channels of the RWST level low low alarm. This is required because the IP2 ESFAS design does not include automatic switchover from the safety injection mode to the recirculation mode of operation based on low low level in the RWST coincident with a safety injection signal.

The LCO requirement for two channels of RWST level indication is satisfied by the OPERABILITY of LT-920 and LT-5751.

APPLICABILITY

The PAM instrumentation LCO is applicable in MODES 1, 2, and 3. These variables are related to the diagnosis and pre-planned actions required to mitigate DBAs. The applicable DBAs are assumed to occur in MODES 1, 2, and 3. In MODES 4, 5, and 6, unit conditions are such that the likelihood of an event that would require PAM instrumentation is low; therefore, the PAM instrumentation is not required to be OPERABLE in these MODES.

ACTIONS

A Note has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed on Table 3.3.3-1. The Completion Time(s) of the inoperable channel(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

BASES

ACTIONS (continued)

A.1

or train

Condition A applies when one or more Functions have one required channel that is inoperable. Required Action A.1 requires restoring the inoperable channel to OPERABLE status within 30 days. The 30 day Completion Time is based on operating experience and takes into account the remaining OPERABLE channel (or in the case of a Function that has only one required channel, other non-Regulatory Guide 1.97 instrument channels to monitor the Function), the passive nature of the instrument (no critical automatic action is assumed to occur from these instruments), and the low probability of an event requiring PAM instrumentation during this interval.

B.1

Condition B applies when the Required Action and associated Completion Time for Condition A are not met. This Required Action specifies initiation of actions in Specification 5.6.6, which requires a written report to be submitted to the NRC immediately. This report discusses the results of the root cause evaluation of the inoperability and identifies proposed restorative actions. This action is appropriate in lieu of a shutdown requirement since alternative actions are identified before loss of functional capability, and given the likelihood of unit conditions that would require information provided by this instrumentation.

C.1

Condition C applies when one or more Functions have two or more inoperable required channels or trains (i.e., two channels or trains inoperable in the same Function). For Functions 1 and 2, Condition C applies when the one required channel is inoperable and there are no OPERABLE channels of the diverse Function that provides redundant indication. Required Action C.1 requires restoring one or more channel in the Function(s) to OPERABLE status within 7 days so that Condition C is no longer applicable. The Completion Time of 7 days is based on the relatively low probability of an event requiring PAM instrument operation and the availability of alternate means to obtain the required information. Continuous operation with two required channels inoperable in a Function is not acceptable because the alternate indications may not fully meet all performance qualification requirements applied to the PAM instrumentation. Therefore, requiring restoration of one inoperable channel of the Function limits the risk that the PAM Function will be in a degraded condition should an accident occur.

BASES

ACTIONS (continued)

E.1 and E.2

If the Required Action and associated Completion Time of Condition C are not met and Table 3.3.3-1 directs entry into Condition E, the unit must be brought to a MODE where the requirements of this LCO do not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and MODE 4 within 12 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

F.1

At Indian Point 2, Function 4 (Reactor Vessel Level Indication System) and Function 10 (Containment Hydrogen Monitor) are not classified as Type A variables based on the evaluations listed in Reference 1. Additionally, alternate methods or diverse variables providing adequate information to make required assessments are available to operators even if these functions are not available. Therefore, plant shutdown within 7 days is not warranted if more than one channel of these Functions are not Operable.

Function 9 (Containment Area Radiation - High Range) and Function 14 (Condensate Storage Tank Level) are Type A variables; however, alternate methods for monitoring these variables are available. Therefore, plant shutdown within 7 days is not warranted if more than one channel of these Functions are not Operable.

If these alternate means are used to monitor a parameter, the Required Action is not to shut down the unit but rather to follow the directions of Specification 5.6.6, in the Administrative Controls section of the TS. The report provided to the NRC should discuss the alternate means used, describe the degree to which the alternate means are equivalent to the installed PAM channels, justify the areas in which they are not equivalent, and provide a schedule for restoring the normal PAM channels.

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that SR 3.3.3.1 and SR 3.3.3.3 apply to each PAM instrumentation Function in Table 3.3.3-1.

BASES

SURVEILLANCE REQUIREMENTS (Continued)

SR 3.3.3.1

Performance of the CHANNEL CHECK once every 31 days ensures that a gross instrumentation failure has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION. The high radiation instrumentation should be compared to similar unit instruments located throughout the unit.

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including isolation, indication, and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit. If the channels are within the criteria, it is an indication that the channels are OPERABLE.

As specified in the SR, a CHANNEL CHECK is only required for those channels that are normally energized. Instruments that are normally isolated or normally not in service are considered de-energized.

The Frequency of 31 days is based on operating experience that demonstrates that channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the LCO required channels.

SR 3.3.3.2 and SR 3.3.3.3

A CHANNEL CALIBRATION is performed every 92 days for the hydrogen monitor and RWST level and every 24 months, or approximately at every refueling for all other Table 3.3.3-1 Functions. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to measured parameter with the necessary range and accuracy. Whenever a sensing element is replaced, the next required CHANNEL CALIBRATION of the Core Exit thermocouple

BASES

SURVEILLANCE REQUIREMENTS (continued)

sensors is accomplished by an inplace cross calibration that compares the other sensing elements with the recently installed sensing element. The Frequency is based on operating experience and consistency with the typical industry refueling cycle.

REFERENCES

1. Safety Evaluation by the Office of Nuclear Reactor Regulation Regarding Conformance to Regulatory Guide 1.97 for Consolidated Edison Company of New York, Inc. Indian Point Nuclear Generating Unit No. 2, Docket No. 50-247, September 27, 1990.
2. Regulatory Guide 1.97, December 1980.
3. NUREG-0737, Supplement 1, "TMI Action Items."
4. UFSAR, Section 7.1.5

BASES

SURVEILLANCE REQUIREMENTS (continued)

The Frequency of 24 months is based upon operating experience and consistency with the typical industry refueling cycle.

SR 3.3.4.4

and reactor trip bypass breaker (RTBB)

and RTBB

RTB

SR 3.3.4.4 is a verification of the proper operation of the reactor trip breaker local open/closed indication every 24 months. This test should verify the OPERABILITY of the ~~reactor trip breakers~~ (RTBs) open and closed indication by actuating the RTBs. This SR can be satisfied by verification of the RTB local indication during performance of RTB testing required by LCO 3.3.1, "Reactor Protection System (RPS) Instrumentation."

REFERENCES

1. 10 CFR 50, Appendix A, GDC 19.
2. UFSAR, Section 7.7.3 and 8.3.

Table B 3.3.4-1 (page 1 of 2)
Remote Shutdown Instrumentation and Controls

FUNCTION/INSTRUMENT OR CONTROL PARAMETER	REQUIRED NUMBER OF FUNCTIONS
1. REACTIVITY CONTROL	
a. Source Range Neutron Flux (NI-5143-1).	1
b. Reactor Trip and Bypass Breaker Position.	1 per breaker
c. Reactor Trip & Bypass Breaker Trip Switch; or 21 MG Set & 22 MG Set Trip Switch.	1 per breaker; or 1 per train
d. Seal Injection Flow (FI-144, FI-143, FI-116 and FI-115)	1 per RCP
2. REACTOR COOLANT SYSTEM PRESSURE CONTROL	
a. 21 Pressurizer Backup Heater Local/Remote transfer switch.	1
b. Pressurizer Pressure (PI-3105-1).	1
3. DECAY HEAT REMOVAL via STEAM GENERATORS	
a. Hot Leg Temperature. (TI-5139 for Loop 21 and TI-5141 for Loop 22)	2
b. Cold Leg Temperature. (TI-5140 for Loop 21 and TI-5142 for Loop 22)	2
c. SG Pressure. (PI-1353, PI-1354, PI-1355 and PI-1356)	1 per SG
d. SG Level. (LI-5001-1 for 21 SG and LI-5002-1 for 22 SG)	2
e. CST Level.	1
f. Atmospheric Steam Dump Valve controls. (Local nitrogen control stations in AFW Pump Building)	1 ~~ABV~~
g. Auxiliary Feedwater Pump 21. (Transfer switch EDC5 and breaker 1B)	1

Table B 3.3.4-1 (page 2 of 2)
Remote Shutdown Instrumentation and Controls

		FUNCTION/INSTRUMENT OR CONTROL PARAMETER	REQUIRED NUMBER OF FUNCTIONS
	h.	AFW Pump suction and discharge pressure ~~(each pump)~~.	1 each per pump
	i.	Transfer switches ~~EDG3 & EDG~~1, ~~Splice box EZG~~4 for 21 RHR, and ~~Splice box EZH1 for~~ 22 RHR.	1 ~~each~~ per pump
4.		RCS INVENTORY CONTROL	
	a.	Pressurizer Level (LI-3101-1)	1
	b.	RWST Level (LI-921)	1
	c.	Charging Pump 23 (Transfer switch EDC4 and breaker 1M)	1
5.		SUPPORT EQUIPMENT	
	a.	CCW Flow from RCP seals (thermal barriers) (FIC-625)	1
	b.	CCW flow to Charging Pumps (FI-637)	1
	c.	CCW flow to RHR Pumps (FIC-645, FIC 646)	2
	d.	Service Water Pumps (Transfer switch EDG3 and breaker 1M for SW Pump 23) (Transfer switch EDG4 and breaker 3M for SW Pump 24)	2
	e.	Component Cooling Water Pump (Transfer switch EDF9 and breaker 2B for CCW Pump 23)	1
	f.	Service Water Pressure at CCW-HX Inlet (PI-1276, PI-1277)	2

3.3 INSTRUMENTATION

3.3.5 Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation

LCO 3.3.5 The following LOP DG start instrumentation shall be OPERABLE:

a. Two channels per bus of the 480 V bus Undervoltage Function on buses 5A, 2A, 3A and 6A;

b. Two channels per bus of the 480 V bus Degraded Voltage Function on buses 5A, 2A, 3A and 6A;

c.1 Three channels per bus of the Station Blackout (SBO) Function on buses 5A and 6A when in MODE 1, 2, 3 and 4; and

c.2 Three channels per bus of the Station Blackout (SBO) Function on either bus 5A or 6A when in MODE 5 and 6.

APPLICABILITY: MODES 1, 2, 3, and 4,
When associated DG is required to be OPERABLE by LCO 3.8.2, "AC Sources - Shutdown."

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
- NOTE - Not applicable in MODE 5 or 6. A. One SBO channel inoperable on one bus.	A.1 Place channel in trip.	7 days

status

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
- NOTE - Not applicable in MODE 5 or 6. B. Two or more SBO channels inoperable on one bus with three OPERABLE SBO channels on the other bus. OR One SBO channel inoperable on both buses.	B.1	Restore to OPERABLE at least three SBO channels on one bus and two SBO channels on the other bus.	48 hours
C. Required Action and Completion Time of A or B not met.	C.1 AND C.2	Be in MODE 3. Be in MODE 5.	6 hours 36 hours
- NOTE - Not applicable in MODE 1, 2, 3 or 4. D. One SBO channel inoperable on a required bus.	D.1	Place channel in trip.	48 hours
E. Two or more SBO channels inoperable on both buses in MODE 1, 2, 3 or 4. OR Required Action and Completion Time of D not met.	E.1	Enter applicable Condition(s) and Required Action(s) for all DGs inoperable.	Immediately

Condition

R3-S7

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
- NOTE - Separate Condition entry is allowed for each bus. F. One Undervoltage Function channel inoperable.	F.1 Restore channel to OPERABLE status.	6 hours
G. - NOTE - Separate Condition entry is allowed for each bus. One Degraded Voltage Function channel inoperable.	G.1 Place channel in trip.	1 hour
H. Required Action and associated Completion Time of Condition F or G not met. OR Two Undervoltage Function channels inoperable on one or more buses. OR Two Degraded Voltage Function channels inoperable on one or more buses.	H.1 Enter applicable Condition(s) and Required Action(s) for the associated DG(s) made inoperable by LOP DG start instrumentation.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.5.1	Perform CHANNEL CHECK of the 480 V bus Degraded Voltage Function.	12 hours
SR 3.3.5.2	Perform TADOT of the 480 V bus Degraded Voltage Function.	31 days
SR 3.3.5.3	Perform TADOT of each of the following: a. 480 V bus Undervoltage Function; and b. 480 V bus SBO Function.	24 months
SR 3.3.5.4	Perform ACTUATION LOGIC TEST of each of the following: a. 480 V bus Undervoltage Function; and b. 480 V bus SBO Function.	24 months
SR 3.3.5.5	Perform CHANNEL CALIBRATION with Allowable Values as follows: a. 480 V bus Undervoltage Function Allowable Value: ≥ 206.6 V with a time delay ≤ 3.7 seconds. b. 480 V bus Degraded Voltage Function Allowable Value: ≥ 419 V and ≤ 423 V with time delays as follows: i. No SI Signal ≥ 204.6 seconds; and ≤ 207 ii. Coincident SI ≥ 9.7 seconds and ≤ 11.6 seconds. 8.4 c. 480 V bus SBO Function Allowable Value: ≥ 198.6 V.	24 months

BASES

BACKGROUND (continued)

Degraded Voltage relays (i.e., channels), two channels per bus on 480 V buses 6A, 2A, 3A and 5A, will detect a degraded voltage condition on any of the four 480 V safeguards buses. Detection of a degraded voltage condition on a 480 V bus will open breakers on the associated bus that connect the 480 V bus to offsite power or the unit auxiliary transformer (i.e., plant main generator). The relays are combined in a two-out-of-two logic to prevent spurious actuation. A two-out-of-two logic for each bus is acceptable because redundancy is provided by the number of DGs available. The degraded voltage function actuation includes time delays to ensure proper coordination with plant electrical transients (large motor starts, fast transfers, etc.). As specified in the acceptance criteria for SR 3.3.5.5, the degraded voltage function will actuate after a short time delay if there is a concurrent safety injection signal and will actuate after a longer time delay if there is no concurrent safety injection signal. The allowable values for this function (including time delays) are established in accordance with Reference 2.

The LOP start actuation is described in UFSAR, Sections 7.5, 8.1 and 8.2 (Ref. 1).

Technical Specification Allowable Values are determined based on the relationship between an analytical limit and a calculated trip setpoint. A detailed discussion of the relative position of the safety limit, analytical limit, allowable value and the trip setpoint with respect to the normal plant operation point is presented in the Bases of LCO 3.3.1, "Reactor Protection System (RPS) Instrumentation."

A detailed description of the methodology used to calculate the channel and bistable device allowable value, including their explicit uncertainties, is provided in Reference 2.

APPLICABLE SAFETY ANALYSES

The LOP DG start instrumentation is required for the Engineered Safety Features (ESF) Systems to function in any accident with a loss of offsite power. Its design basis is that of the ESF Actuation System (ESFAS).

Accident analyses credit the loading of the DG based on the loss of offsite power during a loss of coolant accident (LOCA). The actual DG start has historically been associated with the ESFAS actuation. The DG loading has been included in the delay time associated with each safety system component requiring DG supplied power following a loss of offsite power.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The required channels of LOP DG start instrumentation, in conjunction with the ESF systems powered from the DGs, provide unit protection in the event of any of the analyzed accidents discussed in Reference 1, in which a loss of offsite power is assumed.

The delay times assumed in the safety analysis for the ESF equipment include the 10 second DG start delay, and the appropriate sequencing delay, if applicable. The response times for ESFAS actuated equipment in LCO 3.3.2, ~~"Engineered Safety Feature Actuation System (ESFAS) Instrumentation,"~~ include the appropriate DG loading and sequencing delay.

Loss of the LOP DG Start Instrumentation Function could result in the delay of safety systems initiation when required. This could lead to unacceptable consequences during accidents. During the loss of offsite power the DG powers the motor driven auxiliary feedwater pumps. Failure of these pumps to start would leave only one turbine driven pump, as well as an increased potential for a loss of decay heat removal through the secondary system.

The LOP DG start instrumentation channels satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO for LOP DG start instrumentation requires that the following instrumentation is OPERABLE:

a. Two channels per bus of the 480 V bus Undervoltage Function on buses 5A, 2A, 3A and 6A. Operability requires that both the trip setpoint and the time delay are within the allowable values specified in SR 3.3.5.5. Either of the undervoltage relays will actuate the undervoltage function with additional redundancy provided by the number of DGs available. Additionally, an ESFAS safety injection signal will initiate all of the functions actuated by the undervoltage relays.

b. Two channels per bus of the 480 V bus Degraded Voltage Function on buses 5A, 2A, 3A and 6A. Both channels on each bus are required to be Operable because relays are combined in a two-out-of-two logic to prevent spurious actuation. A two out of two logic for each bus is acceptable because redundancy is provided by the number of DGs available. Operability requires that both the trip setpoint and the time delay are within the allowable values specified in SR 3.3.5.5.

BASES

LCO (continued)

c.1 Three channels per bus of the Station Blackout (SBO) Function on both bus 5A and 6A are required when in MODE 1, 2, 3 and 4. Each set of three SBO undervoltage relays (i.e., channels) is considered a train because, if there is a loss of voltage on 480 V bus 5A or 6A, two out of the three SBO undervoltage relays associated with either train will actuate the undervoltage portion of the SBO function. The SBO actuation logic design, two out of three channels on bus 6A or two out of three on bus 5A, provides sufficient redundancy such that the three channels associated with either bus will actuate the SBO function in conjunction with any single active failure. Actuation logic for the SBO undervoltage function includes input from a safety injection signal and/or a plant trip. If either of these inputs is inoperable, all three channels with the associated train are inoperable. Operability requires that the trip setpoint is within the allowable values specified in SR 3.3.5.5.

c.2 Three channels per bus of the Station Blackout (SBO) Function on either bus 5A or 6A are required when in MODE 5 and 6. As explained in the Bases for LCO 3.8.2, "AC Sources - Shutdown," the Technical Specifications requirements ensure that the unit has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or all onsite power is not required. In MODE 5 and 6, operators have sufficient time to align a DG manually if the SBO function fails to automatically connect a DG to its 480 V bus.

APPLICABILITY

The LOP DG Start Instrumentation Functions are required in MODES 1, 2, 3, and 4 because ESF Functions are designed to provide protection in these MODES. Actuation in MODE 5 or 6 is required whenever a DG must be OPERABLE so that it can perform its function on an LOP or degraded power to the vital bus.

ACTIONS

In the event a channel's trip setpoint is found nonconservative with respect to the Allowable Value, or the channel is found inoperable, then the function that channel provides must be declared inoperable and the LCO Condition entered for the particular protection function affected.

BASES

ACTIONS (continued)

A.1

Condition A applies when one SBO channel on one bus is inoperable. In this Condition, the remaining two OPERABLE channels associated with the affected bus will still actuate the SBO function. Additionally, any two of the three OPERABLE channels associated with the other bus will also actuate the SBO function. Therefore, a Completion Time of 7 days to place the inoperable channel in trip provides adequate time to accomplish required repairs without any significant degradation of safety.

Condition A is modified by a note stating that the Condition is not applicable ~~during~~ in MODE 5 or 6. This note is necessary because three channels per bus of the Station Blackout (SBO) Function are required on either bus 5A or 6A when in MODE 5 and 6.

B.1

Condition B applies when two or more SBO channels on one bus are inoperable but all three SBO channels on the other bus are OPERABLE or when one SBO channel is inoperable on both buses. Note that inoperability of the input from a safety injection signal and/or a plant trip into the SBO actuation logic is equivalent to three inoperable channels on that bus. Therefore, if either of these inputs is inoperable, all three channels are inoperable.

In Condition B, either of the two OPERABLE channels associated with each bus or two OPERABLE channels associated with the OPERABLE bus will still actuate the SBO function on a loss of offsite power to 480 V buses 5A and 6A. Therefore, a Completion Time of 48 hours to restore at least one of the inoperable channels provides adequate time to accomplish required repairs without significant degradation of safety.

Condition B is modified by a note stating that the Condition is not applicable in MODE 5 or 6. This note is necessary because three channels per bus of the Station Blackout (SBO) Function on either bus 5A or 6A are required when in MODE 5 and 6.

BASES

ACTIONS (continued)

C.1 and C.2

If the inoperable SBO channels cannot be restored to OPERABLE status within the required 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 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems.

D.1

Condition D applies when one SBO channel is inoperable on the required bus (i.e., either 480 V bus 5A or 6A) when in MODE 5 or 6. In this Condition, the two remaining OPERABLE SBO channels will accomplish the SBO function. A Completion Time of 48 hours to place the inoperable channel in trip is appropriate because operators have sufficient time to align a DG manually if the SBO function fails to automatically connect a DG to its 480 V bus when in MODE 5 and 6.

E.1

Condition E applies when two or more SBO channels on both buses are inoperable when in MODE 1, 2, 3 or 4. In this Condition, the SBO logic will not perform its required safety function and the DGs will not automatically supply the 480 V safeguards buses as assumed in the accident analysis. However, if an SI signal is not present, the DGs will start automatically but operator action will be required to align the DGs to the associated 480 V buses. Therefore, immediate entry into the applicable Condition(s) and Required Action(s) for all DGs inoperable is appropriate. Condition E applies when the Required Actions and Completion Time of Condition D are not met.

F.1

Condition F applies when one of the two channels of 480 V bus undervoltage function is inoperable. In this Condition, the associated DG will automatically connect to the associated 480 V bus on ~~either~~ an undervoltage signal; however, the design redundancy for this function is lost. Therefore, Required Action F.1 allows 6 hours to restore the required channel to OPERABLE status before the affected DG must be declared inoperable in accordance with Required Action H.1. Condition F is modified by a Note explaining that separate condition entry is allowed for each 480 V bus.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.5.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit.

The Frequency is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the LCO required channels.

SR 3.3.5.2 and SR 3.3.5.3

SR 3.3.5.2 and SR 3.3.5.3 require performance of TADOTs. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable TADOT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. This test is performed every 31 days for the 480 V bus Degraded Voltage Function and every 24 months for the 480 V bus undervoltage function and the SBO ~~undervoltage~~ function. The test checks trip devices that provide actuation signals directly, bypassing the analog process control equipment. For these tests, the relay trip setpoints are verified and adjusted as necessary. The Frequency is based on the known reliability of the relays and controls and the multichannel redundancy available, and has been shown to be acceptable through operating experience.

480 V

BASES

SURVEILLANCE REQUIREMENTS (continued)

and 480 V undervoltage function

<u>SR 3.3.5.4</u>

480 V

SR 3.3.5.4 is the performance of an ACTUATION LOGIC TEST for the SBO ~~Undervoltage~~ Function. This test is performed every 24 months which is consistent with the plant conditions needed to perform the test. This Test is performed in conjunction with the testing of LCO 3.3.2, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation," Function 6.d, Auxiliary Feedwater - Station Blackout. The Surveillance interval is acceptable based on instrument reliability and operating experience.

<u>SR 3.3.5.5</u>

SR 3.3.5.5 is the performance of a CHANNEL CALIBRATION.

The setpoints, as well as the response to a loss of voltage and a degraded voltage test, shall include a single point verification that the trip occurs within the required time delay.

A CHANNEL CALIBRATION is performed every 24 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 a measured parameter within the necessary range and accuracy.

The Frequency of 24 months is based on operating experience and consistency with the typical industry refueling cycle and is justified by the assumption of an 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

REFERENCES

1. UFSAR, Section 7,8 and 14.
2. Indian Point 2 Specification FIX-95-A-001, Guidelines For Preparation Of Instrument Loop Accuracy And Setpoint Determination Calculation.

Table 3.5-1

Engineered Safety Features Initiation Instrument Setting Limits

	No.	Functional Unit	Channel	Setting Limits	
SEE ITS 3.3.2	1.	High Containment Pressure (Hi Level)	Safety Injection	≤ 2.0 psig	
	2.	High Containment Pressure (Hi-Hi Level)	a. Containment Spray b. Steam Line Isolation	≤ 24 psig	
	3.	Pressurizer Low Pressure	Safety Injection	≥ 1833 psig	
	4.	High Differential Pressure Between Steam Lines	Safety Injection	≤ 155 psi	
	5.	High Steam Flow in 2/4 Steam Lines Coincident with Low T_{avg} or Low Steam Line Pressure	a. Safety Injection b. Steam Line Isolation	≤ 40% of full steam flow at zero load ≤ 40% of full steam flow at 20% load ≤ 110% of full steam flow at full load ≥ 540°F T_{avg} ≥ 525 psig steam line pressure	
	6.	Steam Generator Water Level (Low-Low)	Auxiliary Feedwater	≥ 7% of narrow range instrument span each steam generator	LA.3
LCO 3.3.5 SR 3.3.5.5	7.	Station Blackout (Undervoltage)	Auxiliary Feedwater	≥198.6V ~~≥ 40% nominal voltage~~	~~L1~~ A.7.f
LCO 3.3.5 SR 3.3.5.5	8a.	480V Emergency Bus Undervoltage (Loss of Voltage)	------	≥206.6V Time delay ≤ 3.7 sec ~~220V + 100V, -20V~~ ~~3 sec ± 1 sec~~	~~L1~~ A.3.f
LCO 3.3.5 SR 3.3.5.5	8b.	480V Emergency Bus Undervoltage (Degraded Voltage)	------	≥419 & ≤423V NoSI: ≤ 209.0 sec (≤207) SI: ≥9.1 & ≤11.4 sec (8.4) ~~421V ± 6V~~ ~~180 sec ± 30 sec (no SI)~~ ~~10 sec ± 2 sec (coincident)~~	~~L1~~ A.4.f LA.3 165

ITS 3.3.5

ITS Package Revision 2

A.3.e Rev. 1

3.3.5: Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation

Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Surveillance requirements for:
ITS 3.3.5, 480 V Bus Undervoltage Function - LOP DG Start Instrumentation

Description of Change

CTS Table 4.1-1, Item 29.a, 480 V Emergency Bus Undervoltage (Loss of Voltage), requires a channel test and a channel calibration at interval R## (i.e., every 24 months) (See DOC A.6).

ITS SR 3.3.5.3 requires a trip actuating device operational test (TADOT) of the 480 V undervoltage function every 24 months, ITS SR 3.3.5.4 requires an Actuation Logic Test of the 480 V undervoltage function every 24 months and ITS SR 3.3.5.5 requires a channel calibration of the 480 V undervoltage function every 24 months. Therefore, there is no change to the existing requirements.

Justification for Change

This is an administrative change with no impact on safety because there is no change to the existing requirements.

A.3.f Rev. 1

~~3.3.5: Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation~~

~~Category Administrative: No Technical Changes~~

~~DOC Summary:~~

~~Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.5, 480 V Bus Undervoltage Function - LOP DG Start Instrumentation~~

~~Description of Change~~

~~CTS Table 3.5-1, Item 8.a, 480 V Emergency Bus Undervoltage (Loss of Voltage), establishes the nominal trip setpoint as the limiting safety system setting (i.e., the as-left setpoint) for CTS Table 3.5-3, Item 3.a, 480 V Emergency Bus Undervoltage (Loss of Voltage) at greater than or equal to 200 V and less than or equal to 320 V with a time delay greater than or equal to 2 seconds and less than or equal to 4 seconds. This nominal trip setpoint was established based on Indian Point Nuclear Generating Station Unit No. 2 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, and is considered conservative.~~

~~ITS 3.3.5, 480 V Bus Undervoltage Function - LOP DG Start Instrumentation, uses an "Allowable Value" (i.e., as-found setpoint) as the Limiting Safety System Setting.~~

~~Justification for Change~~

~~Indian Point 2 is currently in the process of developing an allowable value of this function using a methodology consistent with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation." When completed, Indian Point 2 will submit to the NRC a copy of site specific methodology and the results. Upon NRC approval, the allowable values will be incorporated into the Improved Technical Specification submittal.~~

~~Use of "Allowable Values" (i.e., as-found setpoints) as the LSSS is considered a less restrictive change. These changes are described and justified in ITS 3.3.2, DOC L.1.~~

A.4.e
Rev. 1

3.3.5: Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation

Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Surveillance requirements for:
ITS 3.3.5, 480 V Bus Degraded Voltage Function - LOP DG Start Instrumentation

Description of Change

CTS Table 4.1-1, Item 29.b, 480 V Emergency Bus Undervoltage (Degraded Voltage), requires a channel check every shift (i.e., every 12 hours per CTS Table 1-1), a channel test at interval M (i.e., every 31 days per CTS Table 1-1), and a channel calibration at interval R## (i.e., every 24 months).

ITS SR 3.3.5.1 maintains the requirement for a channel check every 12 hours. ITS SR 3.3.5.2 maintains the requirement for a Trip Actuating Device Operational Test (TADOT) every 31 days. ITS SR 3.3.5.5 maintains the requirement for a channel calibration every 24 months.

Justification for Change

This is an administrative change with no impact on safety because there is no change to the existing requirement.

A.4.f
Rev. 1

3.3.5: Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation

Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.5, 480 V Bus Degraded Voltage Function - LOP DG Start Instrumentation

Description of Change

CTS Table 3.5-1, Item 8.b, 480 V Emergency Bus Undervoltage (Degraded Voltage), establishes the nominal trip setpoint as the limiting safety system setting (i.e., the as-left setpoint) for CTS Table 3.5-3, Item 3.a, 480 V Emergency Bus Undervoltage (Loss of Voltage) as follows:

Degraded voltage without an ESFAS Safety Injection Signal: the setpoint is greater than or equal to 415 V and less than or equal to 427 V with a time delay at greater than or equal to 150 seconds and less than or equal to 210 seconds.

Degraded voltage with an ESFAS Safety Injection Signal: the setpoint is greater than or equal to 415 V and less than or equal to 427 V with a time delay at greater than or equal to 8 seconds and less than or equal to 12 seconds.

ITS 3.3.5, 480 V bus degraded voltage function - LOP DG Start Instrumentation, uses an "Allowable Value" (i.e., as-found setpoint) as the Limiting Safety System Setting.

Justification for Change

Indian Point 2 is currently in the process of developing an allowable value of this function using a methodology consistent with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation." When completed, Indian Point 2 will submit to the NRC a copy of site specific methodology and the results. Upon NRC approval, the allowable values will be incorporated into the Improved Technical Specification submittal.

Use of "Allowable Values" (i.e., as-found setpoints) as the LSSS is considered a less restrictive change. These changes are described and justified in ITS 3.3.2, DOC L.1.

A.7.e **3.3.5: Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation**

Rev. 1

Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Surveillance requirements for:
ITS 3.3.5, 480 V Bus Station Blackout (SBO) Function - LOP DG Start Instrumentation

Description of Change

CTS Table 4.1-1, Item 30.c, (Auxiliary Feedwater) Station Blackout (Undervoltage), requires a channel test at interval R# (i.e., every 24 months).
ITS SR 3.3.5.3 requires a TADOT every 24 months and ITS SR 3.3.5.4 requires an actuation logic test every 24 months. The combination of these tests maintains the existing requirement and Frequency.

CTS Table 4.1-1, Item 30.c, (Auxiliary Feedwater) Station Blackout (Undervoltage), requires a channel calibration at interval R# (i.e., every 24 months). ITS SR 3.3.5.5 requires a channel calibration every 24 months which maintains the existing requirement and Frequency.

Justification for Change

This is an administrative change with no impact on safety because there is no change to the existing requirements.

A.7.f **3.3.5: Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation**

Rev. 1

Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.5, 480 V Bus Station Blackout (SBO) Function - LOP DG Start Instrumentation

Description of Change

CTS Table 3.5-1, Item 7, Station Blackout (Undervoltage), establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for CTS Table 3.5-3, Item 4.c, (Auxiliary Feedwater) Station Blackout (Start Motor Driven and Steam Driven Pumps) at greater than or equal to 40% of nominal voltage (i.e., 40% of 480 V). This nominal trip setpoint was established based on Indian Point Nuclear Generating Station Unit No. 2 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, and is considered conservative.

ITS 3.3.5, 480 V Bus Station Blackout (SBO) Function - LOP DG Start Instrumentation, uses an "Allowable Value" (i.e., as-found setpoint) as the Limiting Safety System Setting.

Justification for Change

Indian Point 2 is currently in the process of developing an allowable value of this function using a methodology consistent with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation." When completed, Indian Point 2 will submit to the NRC a copy of site specific methodology and the results. Upon NRC approval, the allowable values will be incorporated into the Improved Technical Specification submittal.

Use of "Allowable Values" (i.e., as-found setpoints) as the LSSS is considered a less restrictive change. These changes are described and justified in ITS 3.3.5, DOC L.1.

L.1 **3.3.5: Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation**

Rev. 0

Category Less Restrictive:

DOC Summary:

Replaces the nominal trip setpoint limiting safety system setting (i.e., the as-left setpoint) for the 480 V bus undervoltage and degraded voltage functions with an "Allowable Value" (i.e., as-found setpoint) as the Limiting Safety System Setting.

Description of Change

CTS Table 3.5-1, Item 8.a, 480 V Emergency Bus Undervoltage (Degraded Voltage), and CTS Table 3.5-1, Item 8.b, 480 V Emergency Bus Undervoltage (Degraded Voltage) establish the nominal trip setpoint limiting safety system setting (i.e., the as-left setpoint) for the 480 V bus undervoltage and degraded voltage functions. These nominal trip setpoints were established based on Indian Point Nuclear Generating Station Unit No.2 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, and is considered conservative.

ITS 3.3.5 replaces each of these nominal setpoints with an "Allowable Value" CTS 2.3.1 establishes the nominal trip setpoint (i.e., the as-left setpoint) as the limiting safety system setting for each of the following:

ITS 3.3.1, Function 2.b, Power Range Neutron Flux-Low;
ITS 3.3.1, Function 5, Overtemperature delta T;
ITS 3.3.1, Function 6, Overpower delta T;
ITS 3.3.1, Function 7.a, Pressurizer Pressure-Low;
ITS 3.3.1, Function 7.b, Pressurizer Pressure-High;
ITS 3.3.1, Function 8, Pressurizer Water Level-High;
ITS 3.3.1, Function 9, Reactor Coolant Flow-Low;
ITS 3.3.1, Function 11, RCP Undervoltage (6.9 kV bus);
ITS 3.3.1, Function 12, RCP Underfrequency (6.9 kV bus);
ITS 3.3.1, Function 13, Steam Generator (SG) Water Level low-low; and
associated interlocks for P-6, P-7, P-8, P-10 and Turbine first Stage pressure.

These nominal trip setpoints were established based on Indian Point Nuclear Generating Station Unit No.2 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, and are considered conservative.

ITS 3.3.1 replaces each of these nominal setpoints with an "Allowable Value" that was calculated using a methodology consistent with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation."

Justification for Change

Indian Point 2 is currently in the process of developing an allowable value of this function using a methodology consistent with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation." When completed, Indian Point 2 will submit to the NRC a copy of site specific methodology and the results. Upon NRC approval, the allowable values will be incorporated into the Improved Technical Specification submittal.

This change is needed because the limiting safety system settings established by IP2 Plant Manual, Volume VI, were based on information available at the time regarding instrument performance and methods available at the time for calculating setpoints. This change is acceptable because the allowable values calculated in accordance with Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation" and Regulatory Guide 1.105, "Setpoints for Safety-related Instrumentation" will ensure that sufficient allowance exists between this actual setpoint and the analytical limit to account for known instrument uncertainties. For example these may include design basis accident temperature

LA.2 3.3.5: Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation

Rev. 1 Category Relocated Detail:

DOC Summary:

Relocates requirement for periodic testing of the 480 V emergency bus undervoltage alarm to a licensee document controlled by 10 CFR 50.59 (i.e., IP2 UFSAR 7.5.2.1.12).

Description of Change

CTS Table 4.1-1, No.29c establishes requirements for periodic testing of the 480 V emergency bus undervoltage alarm. As explained in UFSAR 7.5.2.1.12, this alarm is provided to alert the operator when any 480-V bus voltage falls to approximately 94-percent.

ITS LCO 3.3.5 does not establish any requirements for periodic testing of the 480 V emergency bus undervoltage alarm; however, ITS LCO 3.3.5 surveillance requirement maintains existing testing requirements for automatic actuation functions for 480 V undervoltage, degraded voltage, and station blackout trips. Requirements for periodic testing of the 480 V emergency bus undervoltage alarm will be maintained in a licensee document controlled by 10 CFR 50.59 (i.e., IP2 UFSAR) and will be implemented by plant procedures.

Justification for Change

This change is acceptable because automatic protection from a degraded voltage condition on the 480 V buses is provided by CTS Table 3.5-3, Item 3.b, 480 V Bus Degraded Voltage, which trips the respective 480 V feeder breaker and initiates the DG starting sequence on a sustained degraded voltage condition. ITS LCO 3.3.5 maintains the requirement for operability and testing of the 480 V bus degraded voltage function as a Technical Specification Requirement. Additionally, the requirements for periodic testing of the 480 V emergency bus undervoltage alarm will be maintained in a licensee document controlled by 10 CFR 50.59 (i.e., IP2 UFSAR) and will be implemented by plant procedures. Changes to any requirements associated with periodic testing of the 480 V emergency bus undervoltage alarm can be made only in accordance with 10 CFR 50.59.

Need new LA.3

3.3 INSTRUMENTATION

3.3.6 Containment Purge System and Pressure Relief Line Isolation Instrumentation

LCO 3.3.6 The Containment Purge System and Pressure Relief Line Isolation instrumentation for each Function in Table 3.3.6-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3 and 4,
During movement of recently irradiated fuel assemblies within containment.

ACTIONS

- NOTE -

Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One radiation monitoring channel inoperable.	A.1 Restore the affected channel to OPERABLE status.	7 days
-NOTE- Only applicable in MODE 1, 2, 3 or 4. B. One or both automatic actuation trains inoperable. OR Two radiation monitoring channels inoperable. OR Required Action and associated Completion Time of Condition A not met.	B.1 Enter applicable Conditions and Required Actions of LCO 3.6.3, "Containment Isolation Valves," for containment purge system and pressure relief line isolation valves made inoperable by isolation instrumentation.	Immediately

B 3.3 INSTRUMENTATION

B 3.3.6 Containment Purge System and Pressure Relief Line Isolation Instrumentation

BASES

BACKGROUND

Containment purge system and pressure relief line isolation instrumentation closes the containment isolation valves in the Containment Purge System (containment purge supply line and containment purge exhaust line) and the Containment Pressure Relief Line. This action isolates the containment atmosphere from the environment to minimize releases of radioactivity in the event of an accident.

A detailed description of the Containment Purge System (containment purge supply line and containment purge exhaust line) and the Containment Pressure Relief Line is provided in the BACKGROUND of the Bases for Technical Specification 3.6.3, "Containment Isolation Valves."

Both the containment purge supply and exhaust isolation valves (FCV-1170, FCV-1171, FCV-1172, and FCV-1173) and the containment pressure relief line isolation valves (PCV-1190, PCV-1191 and PCV-1192) close when high radiation levels are detected by the Containment Air Particulate Monitor (R-41) or Containment Radioactive Gas Monitor (R-42). The Containment Phase A Isolation ESFAS signal (LCO 3.3.2, Function 3.a) and Containment Spray ESFAS signal (LCO 3.3.2, Function 2) also cause closure of the containment purge isolation valves and the containment pressure relief isolation valves. Although not required to satisfy Technical Specifications, containment purge and containment pressure relief are also isolated when high gas radiation levels are detected in the plant vent (R-44). A failure of the R-44 monitor does not affect operation of the isolation function performed by R-41 and R-42.

APPLICABLE SAFETY ANALYSES

The safety analyses assume that the containment remains intact with penetrations unnecessary for core cooling isolated early in the event, within approximately 60 seconds.

In MODES 1, 2, 3 and 4, isolation instrumentation for the containment purge supply line, containment purge exhaust line and the containment pressure relief line may be open, as needed, for pressure control, ALARA or air quality considerations for personnel entry, or for Surveillances that require the valves to be open consistent with Surveillance Requirements 3.6.3.1 and 3.6.3.2. This is acceptable because the containment purge (supply and exhaust) lines and pressure relief line are equipped with redundant containment isolation valves that are automatically closed upon receipt of a

BASES

APPLICABLE SAFETY ANALYSES (continued)

During movement of recently irradiated fuel (i.e., fuel assemblies that have been part of a critical reactor in the previous 100 hours), the relaxations justified in Reference 2 do not apply. Therefore, during movement of recently irradiated fuel assemblies, LCO 3.9.3, "Containment Penetrations," establishes requirements for containment closure that minimize any release via Containment Purge System and Pressure Relief Line Isolation to the environment resulting from a fuel handling accident that occurs when the reactor has been subcritical for less than the 100 hours assumed in Reference 2. Therefore, LCO 3.3.6, ~~"Containment Purge System and Pressure Relief Line Isolation Instrumentation,"~~ requirements are applicable during the movement of recently irradiated fuel.

The containment purge supply line, containment purge exhaust line and the containment pressure relief line isolation instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii)

LCO

The LCO requirements ensure that the instrumentation necessary to initiate containment purge supply line, containment purge exhaust line and the containment pressure relief line isolation, listed in Table 3.3.6-1, is OPERABLE.

1. Automatic Actuation Logic and Actuation Relays

The LCO requires two trains of Automatic Actuation Logic and Actuation Relays OPERABLE to ensure that no single random failure can prevent automatic actuation.

The Automatic Actuation Logic and Actuation Relays Function is required to be ~~Operable~~ to support the OPERABILITY of all of the functions that isolate the containment purge system and pressure relief line (gaseous and particulate radiation monitors (R-42 and R-41) and ESFAS containment phase A isolation and containment spray initiation signals). There are two trains of automatic actuation logic and actuation relays for the containment purge system and pressure relief line. If one or more of the Containment Spray or Phase A isolation Functions becomes inoperable in such a manner that only the Containment Purge Isolation Function is affected, the Conditions applicable to their Containment Spray and Phase A isolation Functions need not be entered. The less restrictive Actions specified for inoperability of the Containment Purge and Pressure Relief Line Isolation Functions specify sufficient compensatory measures for this case.

BASES

LCO (continued)

2. Containment Radiation

The LCO specifies two required channels of radiation monitors to ensure that the radiation monitoring instrumentation necessary to initiate Containment Purge Isolation remains OPERABLE. The requirement for two channels is satisfied by the Containment Air Particulate Monitor (R-41) and the Containment Radioactive Gas Monitor (R-42). Allowable values and setpoints for these Functions are based on engineering judgement.

Channel OPERABILITY involves more than OPERABILITY of the channel electronics. OPERABILITY may also require correct valve lineups, sample pump operation, and filter motor operation, as well as detector OPERABILITY, if these supporting features are necessary for trip to occur under the conditions assumed by the safety analyses.

3. Containment Isolation - Phase A

Refer to LCO 3.3.2, Function 3.a., for all initiating Functions and requirements. This Function is required only when the associated LCO 3.3.2, "ESFAS Instrumentation," function is required to be OPERABLE.

4. Containment Spray

Refer to LCO 3.3.2, "ESFAS Instrumentation," Function 2, for all initiation functions and requirements. This Function is required only when the associated LCO 3.3.2, "ESFAS Instrumentation," function is required to be OPERABLE.

APPLICABILITY

In MODES 1, 2, 3 or 4, isolation instrumentation for the containment purge supply line, containment purge exhaust line and the containment pressure relief line automatic isolation capability is not required if the associated flow paths are isolated in accordance with the requirements of LCO 3.6.3, "Containment Isolation Valves". If the associated flow paths are open in accordance with Surveillance Requirements 3.6.3.1 or 3.6.3.2, automatic isolation Function 1, Automatic Actuation Logic and Actuation Relays, and Function 3, Containment Isolation - Phase A, and Function 4, Containment Spray, are required as part of the containment isolation function initiated by the ESFAS Instrumentation required by LCO 3.3.2. Function 2.a,

BASES

APPLICABILITY (continued)

Containment Radioactive Gaseous Monitor (R-42), and Function 2.b, Containment Air Particulate Monitor (R-41), are required to be OPERABLE to provide an isolation signal that is diverse to the ESFAS isolation signals.

The Applicability for the containment purge system and pressure relief line isolation on the ESFAS Containment Isolation-Phase A Functions are specified in LCO 3.3.2. Refer to the Bases for LCO 3.3.2 for discussion of the Containment Isolation-Phase A Function Applicability.

and Containment Spray

In MODES 5 and 6, without fuel handling in progress or after 100 hours since reactor shutdown, isolation instrumentation for the containment purge supply line, containment purge exhaust line and the containment pressure relief line need not be OPERABLE because the potential for radioactive releases is minimized and operator action is sufficient to ensure post accident offsite doses are maintained within the limits of Reference 1.

During movement of recently irradiated fuel (i.e., fuel assemblies that have been part of a critical reactor in the previous 100 hours), the relaxations justified in Reference 2 do not apply. Therefore, LCO 3.3.6, "Containment Purge System and Pressure Relief Line Isolation Instrumentation," requirements are applicable during the movement of recently irradiated fuel.

ACTIONS

The most common cause of channel inoperability is outright failure or drift of the bistable or process module sufficient to exceed the tolerance allowed by unit specific calibration procedures. Typically, the drift is found to be small and results in a delay of actuation rather than a total loss of function. This determination is generally made during the performance of a COT, when the process instrumentation is set up for adjustment to bring it within specification. If the Trip Setpoint is less conservative than the tolerance specified by the calibration procedure, the channel must be declared inoperable immediately and the appropriate Condition entered.

A Note has been added to the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed in Table 3.3.6-1. The Completion Time(s) of the inoperable channel(s)/train(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

BASES

ACTIONS (continued)

A.1

Condition A applies to the failure of one containment purge isolation radiation monitor channel (either R-41 or R-42). Since the two containment radiation monitors measure different parameters, failure of a single channel may result in loss of the radiation monitoring Function for certain events. Consequently, the failed channel must be restored to OPERABLE status. A Completion Time of 7 days is allowed to restore the affected channel because the accident analysis assumes that an ESFAS SI signal isolates the containment vent paths. Therefore, the containment radiation monitoring function is not the primary method of ensuring that 10 CFR 50.67 limits are not exceeded.

B.1

Condition B applies to all Containment Purge System and Pressure Relief Line Isolation Functions and addresses the train orientation use of master relays for these Functions. It also addresses the failure of both radiation monitoring channels, or the inability to restore a single failed channel to OPERABLE status in the time allowed for Required Action A.1.

If a train is inoperable, multiple channels are inoperable, or the Required Action and associated Completion Time of Condition A are not met, operation may continue as long as the Required Action for the applicable Conditions of LCO 3.6.3 is met for each valve made inoperable by failure of isolation instrumentation.

A Note is added stating that Condition B is only applicable in MODE 1, 2, 3 or 4.

C.1 and C.2

System

Condition C applies to all Containment Purge and Pressure Relief Line Isolation Functions. It also addresses the failure of multiple radiation monitoring channels, or the inability to restore a single failed channel to OPERABLE status in the time allowed for Required Action A.1. If a train is inoperable, multiple channels are inoperable, or the Required Action and associated Completion Time of Condition A are not met, operation may continue as long as the Required Action to place and maintain containment purge system and ~~exhaust~~ pressure relief line isolation valves in their closed position is met or the applicable Conditions of LCO 3.9.3, "Containment Penetrations," are met for each valve made inoperable by failure of isolation instrumentation. The Completion Time for these Required Actions is immediately.

A Note states that Condition C is applicable during movement of recently irradiated fuel assemblies within containment.

BASES

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that Table 3.3.6-1 determines which SRs apply to which Containment Purge and Exhaust Isolation Functions.

SR 3.3.6.1

Performance of the CHANNEL CHECK once every 24 hours ensures that a gross failure of instrumentation has not occurred and is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit. A CHANNEL CHECK for a single channel instrument is satisfied by verification that the sensor or the signal processing equipment has not drifted outside its limit.

The Frequency is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the LCO required channels.

SR 3.3.6.2

SR 3.3.6.2 is the performance of an ACTUATION LOGIC TEST. This test is performed every 31 days on a STAGGERED TEST BASIS. The Surveillance interval is acceptable based on instrument reliability and industry operating experience.

SR 3.3.6.3

SR 3.3.6.3 is the performance of a MASTER RELAY TEST. The MASTER RELAY TEST is the energizing of the master relay and verifying contact operation. ~~Upon master relay contact operation, a low voltage is injected to the slave relay coil. This voltage is insufficient to pick up the slave relay, but large enough to demonstrate signal path continuity~~. This test is performed every 31 days on a STAGGERED TEST BASIS. The Surveillance interval is acceptable based on instrument reliability and industry operating experience.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.4

A COT is performed every 31 days on each radiation monitoring channel to ensure the entire channel will perform the intended Function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL OPERATIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. This test verifies the capability of the instrumentation to provide the containment purge supply line, containment purge exhaust line and the containment pressure relief line isolation. The setpoint shall be left consistent with the current unit specific calibration procedure tolerance.

SR 3.3.6.5

SR 3.3.6.5 is the performance of a TADOT. This test is a check performed every 24 months that verifies actuation of the end device (i.e., valve cycles, etc.).

The test also includes trip devices that provide actuation signals directly to the actuation relays, bypassing the analog process control equipment. The SR is modified by a Note that excludes verification of setpoints during the TADOT. The Functions tested have no setpoints associated with them.

The Frequency is based on the known reliability of the Function and the redundancy available, and has been shown to be acceptable through operating experience.

SR 3.3.6.6

A CHANNEL CALIBRATION is performed every 24 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 a measured parameter within the necessary range and accuracy. Allowable values and setpoints for these Functions are based on engineering judgement.

The Frequency is based on operating experience and is consistent with the typical industry refueling cycle.

- NOTE -
Only applicable in MODE 1, 2, 3 or 4

3.3 INSTRUMENTATION

3.3.7 Control Room Ventilation System (CRVS) Actuation Instrumentation

LCO 3.3.7 The CRVS actuation instrumentation for each Function in Table 3.3.7-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3 and 4,
During movement of recently irradiated fuel assemblies.

ACTIONS

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

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more Functions inoperable.	A.1	Place one CRVS train in pressurization mode.	72 hours
B. Required Action and associated Completion Time for Condition A not met.	B.1	Be in MODE 3.	6 hours
	AND		
	B.2	Be in MODE 5.	36 hours
C. ~~Required Action and associated Completion Time for Condition A not met during movement of recently irradiated fuel assemblies.~~ One or more Functions inoperable.	C.1	Suspend movement of recently irradiated fuel assemblies.	Immediately

SURVEILLANCE REQUIREMENTS

- NOTE -
Refer to Table 3.3.7-1 to determine which SRs apply for each CRVS Actuation Function.

SURVEILLANCE		FREQUENCY
SR 3.3.7.1	Perform CHANNEL CHECK.	24 hours

- NOTE -
Only applicable during movement of recently irradiated fuel assemblies

Table 3.3.7-1 (page 1 of 1)
CRVS Actuation Instrumentation

FUNCTION	REQUIRED CHANNELS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUES
1. Manual Initiation	1 train	SR 3.3.7.~~3~~4	NA
2. Control Building Air Intake Radiation (R-38-1)	1	SR 3.3.7.1 SR 3.3.7.2 SR 3.3.7.~~4~~3 SR 3.3.7.5	≤ 0.75 mr
3. Control Room Air Intake Radiation (R-38-2)	1	SR 3.3.7.1 SR 3.3.7.2 SR 3.3.7.~~4~~3 SR 3.3.7.5	≤ 0.75 mr
4. Safety Injection	Refer to LCO 3.3.2, "ESFAS Instrumentation," Function 1, for all initiation functions and requirements.		

B 3.3 INSTRUMENTATION

B 3.3.7 Control Room Ventilation System (CRVS) Actuation Instrumentation

BASES

BACKGROUND

The CRVS provides an enclosed control room environment from which the unit can be operated following an uncontrolled release of radioactivity. Upon receipt of an actuation signal, the CRVS initiates filtered pressurization of the control room. This system is described in the Bases for LCO 3.7.10, "Control Room Ventilation System."

Trains

both

using the CRVS mode switch

The actuation instrumentation consists of control room radiation monitor (R-38-2) in the air intake to the control room and the control building radiation monitor (R-38-1). The control room operator can also align and start CRVS manually. The CRVS is also actuated by a safety injection (SI) signal. The SI Function is discussed in LCO 3.3.2, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation."

APPLICABLE SAFETY ANALYSES

The control room must be kept habitable for the operators stationed there during accident recovery and post accident operations.

The CRVS acts to terminate the supply of unfiltered outside air to the control room and pressurize the control room. These actions are necessary to ensure the control room is kept habitable for the operators stationed there during accident recovery and post accident operations by minimizing the radiation exposure of control room personnel.

In MODES 1, 2, 3, and 4, the radiation monitors actuate CRVS as a backup to the SI signal actuation. This ensures initiation of the CRVS during a loss of coolant accident or steam generator tube rupture.

Radiological consequence analyses have been revised to demonstrate compliance with 10 CFR 50.67, Accident Source Term. 10 CFR 50.67 (Ref. 1) requires that accident analyses show adequate radiation protection is provided to permit access to and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem total effective dose equivalent for the duration of the accident (Ref. 2).

BASES

LCO (continued)

2. <u>Control Building Air Intake Radiation Monitor (R-38-1)</u>

   The LCO requires a Control Building Air Intake Radiation Monitor to ensure that the radiation monitoring instrumentation will initiate a control room isolation if isolation on an SI signal fails to occur.

3. <u>Control Room Air Intake Radiation Monitor (R-38-2)</u>

   The LCO requires a Control Room Air Intake Radiation Monitor to ensure that the radiation monitoring instrumentation will initiate a control room isolation if isolation on an SI signal fails to occur.

4. <u>Safety Injection</u>

   Refer to LCO 3.3.2, Function 1, for all initiating Functions and requirements.

APPLICABILITY

In MODES 1, 2, 3 and 4, automatic CRVS actuation is needed to demonstrate compliance with 10 CFR 50.67, Accident Source Term (Ref. 1). OPERABILITY of CRVS Isolation instrumentation ensures that exposures following each event analyzed for Modes 1, 2, 3 and 4 are significantly below the required limits (Ref. 2).

In MODES 5 and 6 without fuel handling in progress or after the reactor has been shutdown for more than 100 hours, automatic CRVS actuation need not be OPERABLE because the potential for radioactive releases is minimized and operator action is sufficient to ensure post accident control room doses are maintained within the limits of Reference 1.

During movement of recently irradiated fuel assemblies either in containment or the fuel handling building, automatic CRVS actuation must be OPERABLE to cope with the release from a fuel handling accident involving recently irradiated fuel. The CRVS is only required to be OPERABLE during fuel handling involving recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 100 hours), due to radioactive decay.

The Applicability for the CRVS actuation on the ESFAS Safety Injection Functions are specified in LCO 3.3.2. Refer to the Bases for LCO 3.3.2 for discussion of the Safety Injection Function Applicability.

BASES

ACTIONS

A Note has been added to the ACTIONS indicating that separate Condition entry is allowed for each Function. The Conditions of this Specification may be entered independently for each Function listed in Table 3.3.7-1 in the accompanying LCO. The Completion Time(s) of the inoperable channel(s)/train(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

one or more functions in Table 3.3.7-1 are

A.1

Condition A applies if ~~either Air Intake Radiation Monitor (R-38-1 or R-38-2), manual initiation or the input from ESFAS Train A or Train B to CRVS is~~ inoperable. If the automatic CRVS start signal from any Function is inoperable, 72 hours is allowed to restore the Function consistent with the limit of 72 hours for loss of CRVS Function allowed by LCO 3.7.10. If the channel/train cannot be restored to OPERABLE status, one CRVS train must be placed in the filtered pressurization mode of operation. This accomplishes the actuation instrumentation Function and places the unit in a conservative mode of operation.

A Note to Condition A clarifies that Required Action A.1 is applicable only in MODE 1, 2, 3 and 4.

B.1 and B.2

Condition B applies when the Required Action and associated Completion Time for Condition A have not been met and the unit is in MODE 1, 2, 3, or 4. The unit must be brought to a MODE in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

C.1

one or more functions are not OPERABLE

Condition C applies when ~~the Required Action and associated Completion Time for Condition A have not been met~~ when recently irradiated fuel assemblies are being moved. Movement of recently irradiated fuel assemblies must be suspended immediately to reduce the risk of accidents that could require CRVS actuation.

SURVEILLANCE REQUIREMENTS

~~Surveillance Requirements apply to the Air Intake Radiation Monitors (R-38-1 and R-38-2) and manual initiation only. Surveillance Requirements for the ESFAS Safety Injection Functions that initiate CRVS are specified in LCO 3.3.2.~~

Replace with NUREG

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.5 RCS Loops - MODE 3

LCO 3.4.5 Two RCS loops shall be OPERABLE and either:

a. Two RCS loops shall be in operation when the Rod Control System is capable of rod withdrawal or

b. One RCS loop shall be in operation when the Rod Control System is not capable of rod withdrawal.

- NOTE -

All reactor coolant pumps may be removed from operation for ≤ 1 hour per 8 hour period provided:

a. No operations are permitted that would cause introduction into the RCS of any coolant with a boron concentration less than that required to meet the SDM of LCO 3.1.1; and

b. Core outlet temperature is maintained at least 10°F below saturation temperature.

APPLICABILITY: MODE 3.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One required RCS loop inoperable.	A.1	Restore required RCS loop to OPERABLE status.	72 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1	Be in MODE 4.	12 hours
C. One required RCS loop not in operation with Rod Control System capable of rod withdrawal.	C.1 OR	Restore required RCS loop to operation.	1 hour

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.6 RCS Loops - MODE 4

LCO 3.4.6 Two loops consisting of any combination of RCS loops and residual heat removal (RHR) loops shall be OPERABLE, and one loop shall be in operation.

- NOTES -

1. All reactor coolant pumps (RCPs) and RHR pumps may be removed from operation for ≤ 1 hour per 8 hour period provided:

    a. No operations are permitted that would cause introduction into the RCS of any coolant with a boron concentration less than that required to meet the SDM of LCO 3.1.1, and

    b. Core outlet temperature is maintained at least 10°F below saturation temperature.

2. No RCP shall be started with any RCS cold leg temperature ≤ 280°F unless the requirements for RCP starting in LCO 3.4.12 are met.

APPLICABILITY: MODE 4.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One required loop inoperable.	A.1	Initiate action to restore a second loop to OPERABLE status.	Immediately
	<u>AND</u>		
	A.2	- NOTE - Only required if RHR loop is operable. Be in Mode 5.	24 hours

BASES

LCO (continued)

flow to remove the decay heat from the core with forced circulation. An additional loop is required to be OPERABLE to provide redundancy for heat removal.

Note 1 permits all RCPs and RHR pumps to be removed from operation for ≤ 1 hour per 8 hour period. The purpose of the Note is to permit tests that are designed to validate various accident analyses values. One of the tests performed during the startup testing program is the validation of rod drop times during cold conditions, both with and without flow. The no flow test may be performed in MODE 3, 4, or 5 and requires that the pumps be stopped for a short period of time. The Note permits the stopping of the pumps in order to perform this test and validate the assumed analysis values. If changes are made to the RCS that would cause a change to the flow characteristics of the RCS, the input values must be revalidated by conducting the test again. The 1 hour time period is acceptable because operating experience has shown that boron stratification is not a problem during this short period with no forced flow.

Utilization of Note 1 is permitted provided the following conditions are met along with any other conditions imposed by maintenance or test procedures:

a. No operations are permitted that would dilute the RCS boron concentration with coolant with boron concentrations less than required to meet SDM of LCO 3.1.1, therefore maintaining the margin to criticality. Boron reduction with coolant at boron concentrations less than required to assure SDM is maintained is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation. This Note does not prohibit injection into the RCS of water with a boron concentration that is equal to or greater than the minimum boron concentration needed to meet the SDM requirement in LCO 3.1.1 even if the water being injected has a lower boron concentration than the water already in the RCS.

b. Core outlet temperature is maintained at least 10°F below saturation temperature, so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

Note 2 requires that the reactor coolant pump starting requirements of LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP)", must be met if RCS temperature is less than or equal to the LTOP Applicability temperature~~, specified in the PTLR~~. This restraint is to prevent a low temperature overpressure event due to a thermal transient when an RCP is started.

BASES

BACKGROUND (continued)

When using SGs depending on natural circulation as the backup decay heat removal system in Mode 5, consideration should be given to the potential need for the following:

(1) the ability to pressurize and control pressure in the RCS;

(2) secondary side water level in the SG relied upon for decay heat removal,

(3) availability of a supply of feedwater, and

(4) availability of an auxiliary feedwater pump capable of injecting into the relied-upon SGs (Ref. 1).

During natural circulation, the SGs secondary side water may boil creating the need to release steam through the atmospheric relief valves or other openings that may exist during shutdown conditions. Therefore, consideration should be given to avoiding the potential for pressurization of the SGs secondary side. It is also important to note that during the decay heat removal using natural circulation, a MODE change (MODE 5 to MODE 4) could occur due to heat up of the RCS (Ref. 1).

APPLICABLE SAFETY ANALYSES

In MODE 5, RCS circulation is considered in the determination of the time available for mitigation of the accidental boron dilution event. The RHR loops provide this circulation.

RCS Loops - MODE 5 (Loops Filled) satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

LCO

The purpose of this LCO is to require that at least one of the RHR loops be OPERABLE and in operation with an additional RHR loop OPERABLE or two SGs with secondary side water level ≥ 0% narrow range. One RHR loop provides sufficient forced circulation to perform the safety functions of the reactor coolant under these conditions. An additional RHR loop is required to be OPERABLE to meet single failure considerations. However, if the standby RHR loop is not OPERABLE, an acceptable alternate method is two SGs with their secondary side water levels ≥ 0% narrow range. Should the operating RHR loop fail, the SGs could be used to remove the decay heat via natural circulation.

BASES

LCO (continued)

Note 1 permits all RHR pumps to be removed from operation for ≤ 1 hour per 8 hour period. The purpose of the Note is to permit tests designed to validate various accident analyses values. One of the tests performed during the startup testing program is the validation of rod drop times during cold conditions, both with and without flow. The no flow test may be performed in MODE 3, 4, or 5 and requires that the pumps be stopped for a short period of time. The Note permits stopping of the pumps in order to perform this test and validate the assumed analysis values. If changes are made to the RCS that would cause a change to the flow characteristics of the RCS, the input values must be revalidated by conducting the test again. The 1 hour time period is acceptable because operating experience has shown that boron stratification is not likely during this short period with no forced flow.

Utilization of Note 1 is permitted provided the following conditions are met, along with any other conditions imposed by test or maintenance procedures:

a. No operations are permitted that would dilute the RCS boron concentration with coolant with boron concentrations less than required to meet SDM of LCO 3.1.1, therefore maintaining the margin to criticality. Boron reduction with coolant at boron concentrations less than required to assure SDM is maintained is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation. This Note does not prohibit injection into the RCS of water with a boron concentration that is equal to or greater than the minimum boron concentration needed to meet the SDM requirement in LCO 3.1.1 even if the water being injected has a lower boron concentration than the water already in the RCS.

b. Core outlet temperature is maintained at least 10°F below saturation temperature, so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

Note 2 allows one RHR loop to be inoperable for a period of up to 2 hours, provided that the other RHR loop is OPERABLE and in operation. This permits periodic surveillance tests to be performed on the inoperable loop during the only time when such testing is safe and possible.

Note 3 requires that the reactor coolant pump starting requirements of LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP)," be met if RCS temperature is less than or equal to the LTOP Applicability temperature specified, LCO 3.4.12. This restriction is to prevent a low temperature overpressure event due to a thermal transient when an RCP is started.

BASES

LCO (continued)

Note 4 provides for an orderly transition from MODE 5 to MODE 4 during a planned heatup by permitting removal of RHR loops from operation when at least one RCS loop is in operation. This Note provides for the transition to MODE 4 where an RCS loop is permitted to be in operation and replaces the RCS circulation function provided by the RHR loops.

RHR pumps are OPERABLE if they are capable of being powered and are able to provide flow if required. An OPERABLE SG can perform as a heat sink via natural circulation when it has an adequate water level and is OPERABLE in accordance with the Steam Generator Tube Surveillance Program.

If the SGs being credited as the redundant method of decay heat removal ~~may~~ depend on natural circulation (Ref. 1) for decay heat removal, the SGs are considered OPERABLE only if:

a. RCS loop and reactor pressure vessel filling and venting are complete; or,

b. RCS pressure has been maintained > 100 psig since the RCP associated with the SG has been operated (which ensures that the SG tubes are filled) or since the loop has been filled and vented.

APPLICABILITY

In MODE 5 with RCS loops filled, this LCO requires forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. One loop of RHR provides sufficient circulation for these purposes. However, one additional RHR loop is required to be OPERABLE, or the secondary side water level of at least two SGs is required to be ≥ 0% narrow range.

Operation in other MODES is covered by:

LCO 3.4.4,	"RCS Loops - MODES 1 and 2;"
LCO 3.4.5,	"RCS Loops - MODE 3;"
LCO 3.4.6,	"RCS Loops - MODE 4;"
LCO 3.4.8,	"RCS Loops - MODE 5, Loops Not Filled;"
LCO 3.9.4,	"Residual Heat Removal (RHR) and Coolant Circulation - High Water Level" (MODE 6), and
LCO 3.9.5,	"Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level" (MODE 6).

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. No required RHR loop OPERABLE. OR Required RHR loop not in operation.	B.1	Suspend operations that would cause introduction into the RCS of any coolant with a boron concentration less than that required to meet SDM of LCO 3.1.1.	Immediately
	AND		
	B.2	Initiate action to restore one RHR loop to OPERABLE status and operation.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.8.1	Verify required RHR loop is in operation.	12 hours
SR 3.4.8.2	- NOTE - Not required to be performed until 24 hours after a required pump is not in operation. Verify correct breaker alignment and indicated power are available to each required RHR pump.	7 days

BASES

BACKGROUND (continued)

Pressurizer heaters are powered from either the offsite source or the diesel generators (DGs) through the four 480 V vital buses as follows:

Safeguards Power Train 5A supports heater group 23 (485 kW);

Safeguards Power Train 6A supports heater group 24 (277 kW); and

Safeguards Power Train 2A/3A supports both:
heater group 21 from Bus 3A (554 kW); and
heater group 22 from Bus 2A (485 kW).

APPLICABLE SAFETY ANALYSES

In MODES 1, 2, and 3, the LCO requirement for a steam bubble is reflected implicitly in the accident analyses. For events that result in pressurizer insurge (e.g., loss of normal feedwater and the loss of load/turbine trip), the analyses assume that the limiting nominal value for the highest initial pressurizer level is 60.6%. This is an analytical limit and does not include an allowance for instrument error. For other events, the nominal value of pressurizer level is assumed because the pressurizer level is automatically controlled and the effect of initial pressurizer level on PCT is small (Ref. 1). Safety analyses performed for lower MODES are not limiting. All analyses performed from a critical reactor condition assume the existence of a steam bubble and saturated conditions in the pressurizer. In making this assumption, the analyses neglect the small fraction of noncondensible gases normally present.

Safety analyses presented in the UFSAR (Ref. 1) do not take credit for pressurizer heater operation; however, an implicit initial condition assumption of the safety analyses is that the RCS is operating at normal pressure.

The maximum pressurizer water level limit, which ensures that a steam bubble exists in the pressurizer, satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii). Although the heaters are not specifically used in accident analysis, the need to maintain subcooling in the long term during loss of offsite power, as indicated in NUREG-0737 (Ref. 2), is the reason for providing an LCO.

LCO

The LCO require~~ment for~~s the pressurizer to be OPERABLE ~~with a water~~ with the actual water level less than or equal to 60.6%. This maximum pressurizer level of 60.6% is the nominal level that is used as the analytical limit for the initial condition in the accident analysis. Pressurizer level

BASES

LCO (continued)

indications in the control room are averaged to come up with a value for comparison to the limit. An additional margin of approximately 5%, should be allowed for instrument error (i.e., the indicated level should not exceed 55.6%).

Limiting the LCO maximum operating water level preserves the steam space for pressure control. The LCO has been established to ensure the capability to establish and maintain pressure control for steady state operation and to minimize the consequences of potential overpressure transients. Requiring the presence of a steam bubble is also consistent with analytical assumptions.

The LCO requires two groups of OPERABLE pressurizer heaters, each with a capacity ≥ 150 kW. Each of the ~~2~~ two groups of pressurizer heaters must be powered from a different DG to ensure that the minimum required capacity of 150 kW can be energized during a loss of offsite power condition assuming the failure of a single DG. The minimum heater capacity required is sufficient to maintain the RCS near normal operating pressure when accounting for heat losses through the pressurizer insulation. By maintaining the pressure near the operating conditions, a wide margin to subcooling can be obtained in the loops. The value of 150 kW has been demonstrated to be adequate to maintain RCS pressures control.

APPLICABILITY

The need for pressure control is most pertinent when core heat can cause the greatest effect on RCS temperature, resulting in the greatest effect on pressurizer level and RCS pressure control. Thus, applicability has been designated for MODES 1 and 2. The applicability is also provided for MODE 3. The purpose is to prevent solid water RCS operation during heatup and cooldown to avoid rapid pressure rises caused by normal operational perturbation, such as reactor coolant pump startup.

In MODES 1, 2, and 3, there is need to maintain the availability of pressurizer heaters, capable of being powered from an emergency power supply. In the event of a loss of offsite power, the initial conditions of these MODES give the greatest demand for maintaining the RCS in a hot pressurized condition with loop subcooling for an extended period. For MODE 4, 5, or 6, it is not necessary to control pressure (by heaters) to ensure loop subcooling for heat transfer when the Residual Heat Removal (RHR) System is in service, and therefore, the LCO is not applicable.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.12 Low Temperature Overpressure Protection (LTOP)

LCO 3.4.12 LTOP shall be OPERABLE in accordance with one of the options in Table 3.4.12-1 and the accumulators shall be isolated.

APPLICABILITY:

- NOTES -

1. Accumulator isolation is only required when accumulator pressure is greater than or equal to the maximum RCS pressure for the coldest existing RCS cold leg temperature allowed by the P/T limit curves provided in Figure 3.4.12-1.

2. If conditions require the use of High Head Safety Injection (HHSI) pumps in the event of loss of RCS inventory, the pumps can be made capable of injecting into the RCS.

3. One HHSI pump may be made capable of injecting into the RCS as needed to support abnormal operations such as emergency boration or response to loss of RHR cooling.

4. SR 3.4.12.8 shall be met prior to starting a reactor coolant pump (RCP) if no other RCPs are in operation.

MODE 4 when any RCS cold leg temperature is ≤ 280°F,
MODE 5,
MODE 6 when the reactor vessel head is on.

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.12.1	- NOTE - Not required to be met when Table 3.4.12-1, Option I, is met. Verify that the number of HHSI pumps and charging pumps capable of injecting into the RCS is within Table 3.4.12-1 limits for plant conditions.	12 hours for pumps with circuit breakers not locked out <u>AND</u> 31 days for pumps with circuit breakers locked out
SR 3.4.12.2	- NOTE - Not required to be met when Table 3.4.12-1, Option A, B, F, G, H or I is met. Verify that the combination of pressurizer pressure, pressurizer level and RCS temperature is within the limits of the Figure specified in Table 3.4.12-1 for the number of HHSI pumps and charging pumps capable of injecting into the RCS.	12 hours
SR 3.4.12.3	Verify each accumulator discharge isolation valve is closed and power removed. <u>OR</u> Verify each accumulator pressure is less than the maximum RCS pressure allowed by the P/T limit curves in ~~the~~ Figure 3.4.12-1 for the coldest existing RCS cold leg temperature.	12 hours 12 hours

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.12 Low Temperature Overpressure Protection (LTOP)

This LCO

BASES

BACKGROUND

LTOP is the combination of restrictions on RCS injection capability, RCS relief capacity or vent size, and reactor coolant pump starting restrictions that limit RCS pressure at low temperatures. The LTOP restrictions ensure the integrity of the reactor coolant pressure boundary (RCPB) is not compromised by violating the pressure and temperature (P/T) limits of 10 CFR 50, Appendix G as described in Reference 1. The reactor vessel is the limiting RCPB component for demonstrating such protection. ~~The PTLR~~ provides the maximum allowable actuation logic setpoints for the power operated relief valves (PORVs) and the maximum RCS pressure for the existing RCS cold leg temperature during cooldown, shutdown, and heatup to meet the Reference 1 requirements during the LTOP MODES.

The reactor vessel material is less tough at low temperatures than at normal operating temperature. As the vessel neutron exposure accumulates, the material toughness decreases and becomes less resistant to pressure stress at low temperatures (Ref. 2). RCS pressure, therefore, is maintained low at low temperatures and is increased only as temperature is increased.

The potential for vessel overpressurization is most acute when the RCS is water solid, which occurs only while shutdown. In a solid condition, a pressure fluctuation can occur more quickly than an operator can react to relieve the condition. Exceeding the RCS P/T limits by a significant amount could cause brittle cracking of the reactor vessel. LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits," requires administrative control of RCS pressure and temperature during heatup and cooldown to prevent exceeding the Reference 1 limits.

This LCO provides RCS overpressure protection by a combination of limiting RCS injection capability of the high head safety injection (HHSI) pumps and the charging pumps based on the pressure relief capability provided by the Overpressure Protection System (OPS) (i.e., redundant power operated relief valves with setpoints based on the RCS temperature) or the size of the vent provided in the RCS for pressure relief. Alternately, if redundant PORVs are not OPERABLE or an RCS vent cannot be established, LTOP protection may be established by limiting the pressurizer level to within limits specified in Figure 3.4.12-2, Figure 3.4.12-3, or Figure 3.4.12-4 consistent with the number of charging pumps and number of HHSI pumps capable of injecting into the RCS. This approach is acceptable because pressurizer level can be maintained such that it will either accommodate any anticipated

BASES

BACKGROUND (continued)

valves when RCS temperature falls below the temperature at which low temperature overpressure protection is required; and, b) provide an open permissive in a two-out-of-two (temperature and pressure) logic for each PORV. When the PORV block valves are open (either manually or as a result of the signal from RCS cold leg temperature) and temperature requirement for PORV opening is met, the PORVs are said to be "armed."

Three channels of RCS pressure are used in a two-out-of-three logic to satisfy the pressure portion of the two-out-of-two (temperature-pressure) logic that actuates each PORV in the overpressure protection mode of operation.

Having the pressure/temperature setpoint of both PORVs within the limits in Figure 3.4.12-1 ensures that the Reference 1 limits will not be exceeded in any analyzed event. Use of two PORVs, each with adequate relieving capability to prevent overpressurization, ensures that a single failure will not prevent PORV actuation. Use of a two-out-of-three logic for pressure and for temperature ensures that a single failure will not cause or prevent an PORV actuation when in the overpressure protection mode of operation.

When a PORV is opened during an increasing pressure transient, the release of coolant will cause the pressure increase to slow and reverse. As the PORV releases coolant, the RCS pressure decreases until a reset pressure is reached and the valve is signaled to close. The pressure continues to decrease below the reset pressure as the valve closes.

<u>RCS Vent Requirements</u>

When the RCS is depressurized, a vent exposed to the containment atmosphere will maintain the RCS at containment ambient pressure in an RCS overpressure transient, if the relieving requirements of the transient do not exceed the capabilities of the vent. Thus, the vent path must be capable of relieving the flow resulting from the limiting LTOP mass or heat input transient, and maintaining pressure below the P/T limits. The required vent capacity may be provided by one or more vent paths.

Depending on the required vent size, RCS vent flow capacity requirements may be met by removing a pressurizer safety valve, blocking open the PORV and disabling its block valve in the open position, removing a PORV's internals, and disabling its block valve in the open position, establishing a vent by opening an RCS vent valve or by removing the pressurizer manway cover. The vent path(s) must be above the level of reactor coolant, so as not to drain the RCS when open.

BASES

APPLICABLE SAFETY ANALYSES

Safety analyses (Ref. 4) demonstrate that the reactor vessel is adequately protected against exceeding the Reference 1 P/T limits. In MODES 1, 2, and 3, and in MODE 4 with all RCS cold leg temperatures exceeding 280°F, the pressurizer safety valves will prevent RCS pressure from exceeding the Reference1 limits. At about 280°F and below, overpressure protection is established by restricting RCS injection capability using the HHSI pumps and the charging pumps based on the pressure relief capability provided by one of the two power operated relief valves with setpoints based on the RCS temperature (i.e., the Overpressure Protection System) or the size of the vent provided in the RCS for pressure relief. Alternately, if redundant PORVs are not Operable or an RCS vent cannot be established, LTOP protection may be established by limiting the pressurizer level to within limits specified in Figure 3.4.12-2, Figure 3.4.12-3, or Figure 3.4.12-4 depending on the number of charging pumps and number of HHSI pumps capable of injecting into the RCS. This approach is acceptable because pressurizer level can be maintained such that it will either accommodate any anticipated pressure surge or allow operators time to react to any unanticipated pressure surge. When pressurizer level is used to satisfy LTOP requirements, operator action is assumed to terminate an unplanned HHSI pump injection within 10 minutes. The LTOP analysis also assumes that the RCS accumulators are either isolated or depressurized whenever LTOP requirements are applicable.

The actual temperature at which the pressure in the P/T limit curve falls below the pressurizer safety valve setpoint increases as the reactor vessel material toughness decreases due to neutron embrittlement. Each time the P/T ~~PTLR~~ curves are revised, LTOP must be re-evaluated to ensure its functional requirements can still be met using the RCS relief valve method or the depressurized and vented RCS condition.

Table 3.4.12-1 and Figures 3.4.12-1 through 3.4.12-6 contain the acceptance limits that define the LTOP requirements. Any change to the RCS must be evaluated against the Reference 4 analyses to determine the impact of the change on the LTOP acceptance limits.

Transients that are capable of overpressurizing the RCS are categorized as either mass or heat input transients, examples of which follow:

<u>Mass Input Type Transients</u>

a. Inadvertent safety injection or

b. Charging/letdown flow mismatch.

BASES

LCO (continued)

Options C, D or E are used only when the required PORVs in OPS mode are not Operable and there is no vent path established. These options depend on maintaining the combination of pressurizer pressure, pressurizer level and RCS temperature within the limits specified in Figure 3.4.12-2, Figure 3.4.12-3, or Figure 3.4.12-4 depending on the number of HHSI pumps ~~and~~ charging pumps capable of injecting into the RCS.

Options F, G, H and I satisfy LTOP requirements when the RCS is depressurized and an RCS vent of the required size is maintained. A fully blocked open PORV or a PORV with the internals removed with the associated block valve blocked open establishes a vent path ≥ 2.00 square inches. Other methods for establishing a vent of the required size are also acceptable.

Each of these methods of overpressure prevention is capable of mitigating the limiting LTOP transient.

The LCO is modified by four Notes. Note 1 states that accumulator isolation (i.e., valve closed and power removed as specified in SR 3.4.12.3) is only required when the accumulator pressure is more than or at the maximum RCS pressure for the coldest existing temperature, as allowed by the P/T limit curves. This note permits the accumulator discharge isolation valve Surveillance to be performed only under these pressure and temperature conditions.

Note 2 allows the HHSI pumps to be made capable of injecting into the RCS if required to respond to a loss of RCS inventory. Note 3 allows one HHSI pump to be made capable of injecting into the RCS as needed for emergency boration or in response to loss of RHR cooling. Note 4 specifies that SR 3.4.12.8 must be met when starting any RCP to ensure that temperature asymmetry within the RCS or between the RCS and steam generators does not result in a pressure increase that could exceed LTOP relief capacity.

APPLICABILITY

This LCO is applicable in MODE 4 when any RCS cold leg temperature is ≤ 280°F, in MODE 5, and in MODE 6 when the reactor vessel head is on. The pressurizer safety valves provide overpressure protection that meets the Reference 1 P/T limits above 280°F. When the reactor vessel head is off, overpressurization cannot occur.

BASES

ACTIONS (continued)

E.1

The RCS must be depressurized and a vent must be established within 8 hours when:

a. Both required PORVs are inoperable,

b. A Required Action and associated Completion Time of Condition A or D is not met, or

c. LTOP is inoperable for any reason other than Condition A B, C or D.

The vent must be consistent with Table 3.4.12-1, Options F, G, H or I, to ensure that the flow capacity is greater than that required for the worst case mass input transient reasonable during the applicable MODES. This action is needed to protect the RCPB from a low temperature overpressure event and a possible brittle failure of the reactor vessel.

Required Action E.1 requires that injection capability be limited in accordance with Table 3.4.12-1 for existing plant conditions to minimize the potential for an overpressure event while the plant is being depressurized and a vent path established.

The Completion Time of 8 hours for depressurizing and establishing the vent required by Table 3.4.12-1 considers the time required to place the plant in this Condition and the relatively low probability of an overpressure event during this time period due to increased operator awareness of administrative control requirements.

SURVEILLANCE REQUIREMENTS

SR 3.4.12.1, SR 3.4.12.2, and SR 3.4.12.3

To minimize the potential for a low temperature overpressure event by limiting the mass input capability, any HHSI or charging pump above the specified limit is verified incapable of injecting into the RCS and the accumulator discharge isolation valves are verified closed and locked out. The HHSI pumps and charging pumps are rendered incapable of injecting into the RCS through removing the power from the pumps by racking the breakers out under administrative control. An alternate method of LTOP control may be employed using at least two independent means to prevent a pump start such that a single failure or single action will not result in an

BASES

SURVEILLANCE REQUIREMENTS (continued)

injection into the RCS. This may be accomplished through the pump control switch being placed in pull to lock and at least one valve in the discharge flow path being closed.

The Frequency of 12 hours ~~for components with circuit breakers not locked out~~ (and 31 days for pumps with circuit breakers locked out) is sufficient, considering other indications and alarms available to the operator in the control room, to verify the required status of the equipment. SR 3.4.12.1 is modified by a Note that permits not performing the required verification that the number of HHSI pumps and charging pumps capable of injecting into the RCS is within Table 3.4.12-1 limits when Option I is met. This is acceptable because Table 3.4.12-1, Option I, does not impose any limitations on the status of HHSI pumps and charging pumps.

SR 3.4.12.2 is modified by a Note that permits not performing the required verification that pressurizer pressure, pressurizer level and RCS temperature are within limits for the number of HHSI pumps and charging pumps capable of injecting into the RCS unless when Table 3.4.12-1, Option A, B, F, G, H or I, is being used to meet LTOP requirements. This is acceptable because these options do not impose any restrictions on the combination of pressurizer pressure, pressurizer level and RCS temperature.

<u>SR 3.4.12.4</u>

The RCS vent ≥ 2.00 or ≥ 5.00 square inches is proven OPERABLE by verifying its open condition either:

a. Once every ~~12~~ 24 hours for a valve that is not locked (valves that are sealed or secured in the open position are considered "locked" in this context) or

b. Once every 31 days for other vent path(s) (e.g., a vent valve that is locked, sealed, or secured in position or a removed PORV (for a vent ≥ 2.00 square inches per PORV) or a pressurizer safety valve (for a vent ≥ 5.00 square inches) or open manway also fits this category).

The passive vent path arrangement must only be open to be OPERABLE. This Surveillance is required to be met if the vent is being used to satisfy the pressure relief requirements of Table 3.4.12-1, Options F through I.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.12.5

The PORV block valve must be verified open every 72 hours to provide the flow path for each required PORV to perform its function when actuated. The valve must be remotely verified open in the main control room. This Surveillance is performed only if the PORV is being used to satisfy the LCO.

The block valve is a remotely controlled, motor operated valve that opens automatically below the LTOP Applicability temperature. The power to the valve operator is not required to be removed, and the manual operator is not required to be locked in the open position. Thus, the block valve can be closed in the event the PORV develops excessive leakage or does not close (sticks open) after relieving an overpressure situation.

The 72 hour Frequency is considered adequate in view of other administrative controls available to the operator in the control room, such as valve position indication, that verify that the PORV block valve remains open.

SR 3.4.12.6

Performance of a COT on each required PORV is required within 12 hours after decreasing RCS temperature to less than or equal to LTOP Applicability temperature and every 31 days thereafter to verify and, as necessary, adjust its lift setpoint. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable COT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. The COT will verify the setpoint is within ~~the~~ Figure 3.4.12-1 allowed maximum limits. PORV actuation could depressurize the RCS and is not required.

allowance

The 12 hour ~~Frequency~~ considers the unlikelihood of a low temperature overpressure event during this time.

A Note has been added indicating that this SR is required to be performed (i.e., completed) within 12 hours after decreasing RCS cold leg temperature to ≤ 280°F.

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.4.13.1	- NOTE - Not required to be performed in MODE 3 or 4 until 12 hours of steady state operation. Verify RCS Operational leakage is within limits by performance of RCS water inventory balance.	72 hours
SR 3.4.13.2	Verify steam generator tube integrity is in accordance with the Steam Generator Tube Surveillance Program.	In accordance with the Steam Generator Tube Surveillance Program

BASES

APPLICABLE SAFETY ANALYSES (continued)

The RCS operational LEAKAGE satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

RCS operational LEAKAGE shall be limited to:

a. Pressure Boundary LEAKAGE

No pressure boundary LEAKAGE is allowed, being indicative of material deterioration. LEAKAGE of this type is unacceptable as the leak itself could cause further deterioration, resulting in higher LEAKAGE. Violation of this LCO could result in continued degradation of the RCPB. LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE.

b. Unidentified LEAKAGE

One gallon per minute (gpm) of unidentified LEAKAGE is allowed as a reasonable minimum detectable amount that the containment air monitoring and containment sump level monitoring equipment can detect within a reasonable time period. Violation of this LCO could result in continued degradation of the RCPB, if the LEAKAGE is from the pressure boundary.

c. Identified LEAKAGE

Up to 10 gpm of identified LEAKAGE is considered allowable because LEAKAGE is from known sources that do not interfere with detection of unidentified LEAKAGE and is well within the capability of the RCS Makeup System. Identified LEAKAGE includes LEAKAGE to the containment from specifically known and located sources, but does not include pressure boundary LEAKAGE or controlled reactor coolant pump (RCP) seal leakoff (a normal function not considered LEAKAGE). Violation of this LCO could result in continued degradation of a component or system.

d. Primary to Secondary LEAKAGE through Any One SG

The 150 gpd (0.1 gpm) limit for primary to secondary leakage in each of the four SGs is part of the performance criteria for the SG tube surveillance program required by Technical Specification 5.5.7, Steam Generator (SG) Tube Surveillance Program, and Reference 6. SG leakage monitoring and the associated limit allows operators to safely

BASES

LCO (continued)

respond to situations in which tube integrity becomes impaired before significant leakage or tube failure occurs.

Note that primary to secondary ~~leakage~~ is also counted as identified LEAKAGE in accordance with Technical Specification 1.1, "Definitions."

APPLICABILITY

In MODES 1, 2, 3, and 4, the potential for RCPB LEAKAGE is greatest when the RCS is pressurized.

In MODES 5 and 6, LEAKAGE limits are not required because the reactor coolant pressure is far lower, resulting in lower stresses and reduced potentials for LEAKAGE.

LCO 3.4.14, "RCS Pressure Isolation Valve (PIV) Leakage," measures leakage through each individual PIV and can impact this LCO. Of the two PIVs in series in each isolated line, leakage measured through one PIV does not result in RCS LEAKAGE when the other is leak tight. If both valves leak and result in a loss of mass from the RCS, the loss must be included in the allowable identified LEAKAGE.

ACTIONS

A.1

Unidentified LEAKAGE, identified LEAKAGE, or primary to secondary LEAKAGE in excess of the LCO limits must be reduced to within limits within 4 hours. This Completion Time allows time to verify leakage rates and either identify unidentified LEAKAGE or reduce LEAKAGE to within limits before the reactor must be shut down. This action is necessary to prevent further deterioration of the RCPB.

B.1 and B.2

If any pressure boundary LEAKAGE exists, or if unidentified LEAKAGE, identified LEAKAGE, or primary to secondary LEAKAGE cannot be reduced to within limits within 4 hours, the reactor must be brought to lower pressure conditions to reduce the severity of the LEAKAGE and its potential consequences. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. The reactor must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours. This action reduces the LEAKAGE and also reduces the factors that tend to degrade the pressure boundary.

BASES

LCO (continued)

The LCO PIV leakage limit is a maximum limit of 5 gpm. However, if the leakage is greater than 1.0 gpm and the leak test indicates that there is significant deterioration from the previous leak test, then the results are unacceptable because of the adverse trend. Significant deterioration is indicated when the leakage is greater than the results of the previous test plus one-half of the margin following the previous test (i.e., margin following previous test is the 5.0 gpm limit minus the results of the previous test).

Leakage limit acceptance criteria is based on the leakage rate that would exist when the RCS is at normal operating pressure (i.e., ≥ 2215 psig and ≤ 2255 psig). Reference 7 permits leakage testing at a lower pressure differential than between the specified maximum RCS pressure and the normal pressure of the connected system during RCS operation (the maximum pressure differential) in those types of valves in which the higher service pressure will tend to diminish the overall leakage channel opening. In such cases, the observed rate may be adjusted to the maximum pressure differential by assuming leakage is directly proportional to the pressure differential to the one-half power. Minimum test differential pressure is 150 psid. Leakage may be measured indirectly (as from the performance of pressure indicators) if accomplished in accordance with approved procedures and supported by computations showing the method is capable of demonstrating valve compliance with the leakage criteria.

This LCO also requires that RCS boundary valves 730 and 731 are closed and de-energized within 24 hours after securing from use of the RHR in decay heat removal mode.

APPLICABILITY

In MODES 1, 2, 3, and 4, this LCO applies because the PIV leakage potential is greatest when the RCS is pressurized. In MODE 4, valves in the RHR flow path are not required to meet the requirements of this LCO when in, or during the transition to or from, the RHR mode of operation.

In MODES 5 and 6, leakage limits are not provided because the lower reactor coolant pressure results in a reduced potential for leakage and for a LOCA outside the containment.

BASES

LCO (continued)

high degree of confidence that extremely small leaks are detected in time to allow actions to place the plant in a safe condition, when RCS LEAKAGE indicates possible RCPB degradation.

The LCO is satisfied when monitors of diverse measurement means are available. Thus, the containment sump monitor, in combination with a gaseous or particulate radioactivity monitor and the containment fan cooler condensate flow rate monitor, provides an acceptable minimum.

The following instruments may be used to satisfy requirements for diverse RCS leakage monitoring requirements:

a. Requirement for one containment sump (level or discharge flow) monitor may be satisfied by any one of the following instruments:

   LT-940, LT-941, LT-3300, LT-3303, LT-3304 if a containment sump level instrument is used to meet this requirement; or

   FIT-3401 if containment sump discharge flow is used to meet this requirement.

b. Requirement for one containment atmosphere radioactivity monitor (gaseous or particulate) may be satisfied by either R-41, Containment Air Particulate Monitor, or R-42, Containment Air Gaseous Monitor. Note that either FCU 22 or FCU 25 should be in operation to provide representative sampling to the R-41 and R-42 Radiation Monitors. If neither FCU 22 or FCU 25 are in operation, plant operating procedures provide direction for use of temporary sampling hoses that may be used to ensure R-41 and R-42 receive representative samples.

c. Requirement for one containment fan cooler condensate flow rate monitor is satisfied by one condensate flow ~~monitors~~ monitor associated with any FCU with fan in operation and cooling water flow through the unit.

APPLICABILITY

Because of elevated RCS temperature and pressure in MODES 1, 2, 3, and 4, RCS leakage detection instrumentation is required to be OPERABLE.

In MODE 5 or 6, the temperature is to be ≤ 200°F and pressure is maintained low or at atmospheric pressure. Since the temperatures and pressures are far lower than those for MODES 1, 2, 3, and 4, the likelihood of leakage and crack propagation are much smaller. Therefore, the requirements of this LCO are not applicable in MODES 5 and 6.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.16 RCS Specific Activity

LCO 3.4.16 The specific activity of the reactor coolant shall be within limits.

APPLICABILITY: MODES 1 and 2,
MODE 3 with RCS average temperature (T_{avg}) ≥ 500°F.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. DOSE EQUIVALENT I-131 > 1.0 µCi/gm.	- NOTE - LCO 3.0.4.c is applicable.	
	A.1 Verify DOSE EQUIVALENT I-131 is ≤ 60.0 µCi/gm.	Once per 4 hours
	AND	
	A.2 Restore DOSE EQUIVALENT I-131 to within limit.	48 hours
B. Gross specific activity of the reactor coolant not within limit.	B.1 Be in MODE 3 with T_{avg} < 500°F.	6 hours
C. Required Action and associated Completion Time of Condition A not met. OR DOSE EQUIVALENT I-131 > 60.0 µCi/gm.	C.1 Be in MODE 3 with T_{avg} < 500°F.	6 hours

BASES

APPLICABILITY (continued)

In MODE 3, with RCS pressure ≤ 1000 psig, and in MODES 4, 5, and 6, the accumulator motor operated isolation valves are closed to isolate the accumulators from the RCS. This allows RCS cooldown and depressurization without discharging the accumulators into the RCS or requiring depressurization of the accumulators.

ACTIONS

A.1

If the boron concentration of one accumulator is not within limits of SR 3.5.1.4, it must be returned to within the limits within 72 hours. In this Condition, ability to maintain subcriticality or minimum boron precipitation time may be reduced. The boron in the accumulators contributes to the assumption that the combined ECCS water in the partially recovered core during the early reflooding phase of a large break LOCA is sufficient to keep that portion of the core subcritical. One accumulator below the minimum boron concentration limit, however, will have no effect on available ECCS water and an insignificant effect on core subcriticality during reflood. Boiling of ECCS water in the core during reflood concentrates boron in the saturated liquid that remains in the core. In addition, current analysis techniques demonstrate that the accumulators do not discharge following a large main steam line break for the majority of plants. Even if they do discharge, their impact is minor and not a design limiting event. Thus, 72 hours is allowed to return the boron concentration to within limits.

B.1

If one accumulator is inoperable for a reason other than boron concentration, the accumulator must be returned to OPERABLE status within 24 hours. In this Condition, the required contents of three accumulators cannot be assumed to reach the core during a LOCA. Due to the severity of the consequences should a LOCA occur in these conditions, the 24 hours Completion Time to open the valve, remove power to the valve, or restore the proper water volume or nitrogen cover pressure ensures that prompt action will be taken to return the inoperable accumulator to OPERABLE status. The Completion Time minimizes the potential for exposure of the plant to a LOCA under these conditions. The 24 hours allowed to restore an inoperable accumulator to OPERABLE status is justified in WCAP-15049, Rev. 1 (Ref. 4).

BASES

BACKGROUND (continued)

RCS cold legs will place the plant outside the design bases. Therefore, flow through both ECCS injection flow paths is required to satisfy the ECCS safety function of the Recirculation System (i.e., both flow paths are required to support Operability of the ECCS function of either of the Recirculation System pumps).

Containment

The three ECCS systems (3 HHSI, 2 RHR and 2 Recirculation) are grouped into three trains (5A, 2A/3A and 6A) such that any 2 of the 3 trains are capable of meeting all ECCS capability assumed in the accident analysis. Each ECCS train consists of the following:

a. ECCS Train 5A includes subsystems HHSI 21 and containment recirculation 21;

b. ECCS Train 2A/3A includes subsystems HHSI 22 and RHR 21; and,

c. ECCS Train 6A includes subsystems HHSI 23, RHR 22, and containment recirculation 22.

The ECCS trains use the same designation as the Safeguards Power Trains required by LCO 3.8.9, Distribution Systems - Operating, with Safeguards Power Train 5A supported by DG 21, Safeguards Power Train 2A/3A supported by DG 22, Safeguards Power Train 6A supported by DG 23.

The ECCS accumulators and the RWST are also part of the ECCS, but are not considered part of an ECCS flow path as described by this LCO.

Each of the subsystems (3 HHSI, 2 RHR and 2 Recirculation) are interconnected and redundant such that any combination of 2 HHSI pumps, 1 RHR pump and 1 recirculation pump is capable of supplying 100% of the flow required to mitigate the accident consequences. This interconnecting and redundant subsystem design provides the operators with the ability to utilize components from different trains to achieve the required 100% flow to the core. The design intent is that any two of the three safeguards power trains is capable of providing 100% of the required ECCS flow; however, any combination of the minimum number of pumps is capable of providing 100% of the required ECCS flow.

During the injection phase of LOCA recovery, a suction header supplies water from the RWST to the HHSI and RHR pumps. The discharge from the HH SI and RHR pumps divides and feeds an injection line to each of the RCS cold legs. Control valves are set to balance the HHSI flow to the RCS. This

BASES

BACKGROUND (continued)

balance ensures sufficient flow to the core to meet the analysis assumptions following a LOCA in one of the RCS cold legs. Additionally, orifices on the HHSI pump discharge prevent pump runout due to increased flow as the RCS depressurizes during an accident.

HHSI

For LOCAs that are too small to depressurize the RCS below the shutoff head of the SI pumps, the charging pumps supply water until the RCS pressure decreases below the SI pump shutoff head. During this period, the steam generators are used to provide part of the core cooling function.

During the recirculation phase of LOCA recovery, the containment recirculation pumps take suction from the containment recirculation sump and direct flow through the RHR heat exchangers to the cold legs. The RHR pumps can also be used to provide a backup method of recirculation because the RHR pump suction is transferred to the containment sump. The RHR pumps then supply recirculation flow directly and can also supply the suction of the HHSI pumps. Initially, recirculation is through the same paths as the injection phase. Subsequently, recirculation alternates injection between the hot and cold legs.

The ECCS also functions to supply borated water to the reactor core following increased heat removal events, such as a main steam line break (MSLB). The limiting design conditions occur when the negative moderator temperature coefficient is highly negative, such as at the end of each cycle.

During low temperature conditions in the RCS, limitations are placed on the maximum number of HHSI pumps that may be capable of injecting into the RCS. Refer to the Bases for LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) ~~System~~," for the basis of these requirements.

The ECCS subsystems, except for the containment recirculation subsystems, are actuated upon receipt of an SI signal. The actuation of safeguard loads is accomplished in a programmed time sequence. If offsite power is available, the safeguard loads start immediately in the programmed sequence. If offsite power is not available, the Engineered Safety Feature (ESF) buses shed normal operating loads and are connected to the emergency diesel generators (EDGs). Safeguard loads are then actuated in the programmed time sequence. The time delay associated with diesel starting, sequenced loading, and pump starting determines the time required before pumped flow is available to the core following a LOCA.

BASES

BACKGROUND (continued)

The active ECCS components, along with the passive accumulators and the RWST covered in LCO 3.5.1, "Accumulators," and LCO 3.5.4, "Refueling Water Storage Tank (RWST)," provide the cooling water necessary to meet GDC 35 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The LCO helps to ensure that the following acceptance criteria for the ECCS, established by 10 CFR 50.46 (Ref. 2), will be met following a LOCA:

a. Maximum fuel element cladding temperature is ≤ 2200°F,

b. Maximum cladding oxidation is ≤ 0.17 times the total cladding thickness before oxidation,

c. Maximum hydrogen generation from a zirconium water reaction is ≤ 0.01 times the hypothetical amount generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react,

d. Core is maintained in a coolable geometry, and

e. Adequate long term core cooling capability is maintained.

The LCO also limits the potential for a post trip return to power following an MSLB event and ensures that containment temperature limits are met.

Each ECCS subsystem is taken credit for in a large break LOCA event at full power (Refs. 3 and 4). This event establishes the requirement for runout flow for the ECCS pumps, as well as the maximum response time for their actuation. The SI pumps are credited in a small break LOCA event. The OPERABILITY requirements for the ECCS are based on the following LOCA analysis assumptions:

HHSI

a. A large break LOCA event, with loss of offsite power and the loss of one of the three safeguards power trains is assumed for the determination of pumped Emergency Core Cooling System (ECCS) flow during the LOCA. However, all three safeguards power trains were assumed to operate in the calculation of containment backpressure. This will conservatively bound the possible single failures (UFSAR 14.3.3.2); and

BASES

pump 22

it

LCO (continued)

either HHSI pump 21 or 23 is inoperable, HHSI is OPERABLE if will automatically align or is manually aligned to replace the inoperable HHSI pump. The ECCS analyses assume high head safety injection into all four RCS cold legs (including the faulted loop). The isolation of high head safety injection flow to any of the RCS cold legs will place the plant outside the design bases. Therefore, flow through both ECCS injection flow paths is required to satisfy the safety function of the high head safety injection system (i.e., both flow paths are required to support ~~Operability~~ of two or more HHSI pumps).

Each ECCS RHR subsystem consists of one RHR pump and one RHR heat exchanger as well as associated piping and valves to transfer water from the suction source to the core. Although either RHR heat exchanger may be credited for either RHR subsystem, one RHR heat exchanger must be OPERABLE for each OPERABLE RHR injection subsystem. The ECCS analyses assume RHR injection into all four RCS cold legs (including the faulted loop).

Each containment recirculation subsystem consists of one Containment Recirculation pump and one RHR heat exchanger as well as associated instrumentation, piping and valves to transfer water from the suction source to the core. Although either RHR heat exchanger may be credited for either Containment Recirculation subsystem, one RHR heat exchanger must be OPERABLE for each OPERABLE Containment Recirculation subsystem.

During an event requiring ECCS actuation, a flow path is required to provide an abundant supply of water from the RWST to the RCS via the HHSI and RHR pumps and their respective supply headers to each of the four cold leg injection nozzles. In the long term, this flow path may be switched to take its supply from the containment recirculation sump using the containment recirculation pumps or, alternately, the containment sump using the RHR pumps and to supply its flow to the RCS hot and cold legs.

The flow path for each ECCS pump must maintain its designed independence to ensure that no single failure can disable more than one ECCS pump.

BASES

LCO (continued)

As indicated in the LCO Note, the SI flow paths may be isolated for 2 hours in MODE 3, under controlled conditions, to perform pressure isolation valve testing per SR 3.4.14.1. The flow path is readily restorable from the control room or the valves are opened under administrative controls that ensure prompt closure when required. These administrative controls consist of stationing a dedicated operator at the valve controls, who is in continuous communication with the control room.

The two auxiliary component cooling water pumps are started during the injection phase to maintain component cooling water flow to the containment recirculation pump motor coolers; however, this cooling function is not required to protect the recirculation pump motors from the containment atmosphere. Therefore, the auxiliary component cooling water pumps are not required for containment recirculation pump operability.

APPLICABILITY

In MODES 1, 2, and 3, the ECCS OPERABILITY requirements for the limiting Design Basis Accident, a large break LOCA, are based on full power operation. Although reduced power would not require the same level of performance, the accident analysis does not provide for reduced cooling requirements when at low reactor power or in MODE 3. The HHSI pump performance requirements are based on a small break LOCA. MODE 2 and MODE 3 requirements are bounded by the MODE 1 analysis.

This LCO is only applicable in MODE 3 and above. In MODE 4, the SI signal setpoint is manually bypassed by operator control, and system functional requirements are relaxed as described in LCO 3.5.3, "ECCS - Shutdown."

In MODES 5 and 6, plant conditions are such that the probability of an event requiring ECCS injection is extremely low. Core cooling requirements in MODE 5 are addressed by LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled," and LCO 3.4.8, "RCS Loops - MODE 5, Loops Not Filled." MODE 6 core cooling requirements are addressed by LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level," and LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level."

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.7

and

Periodic inspections of the containment and recirculation sumps ensure that they are unrestricted and stay in proper operating condition. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage on the need to have access to the location. This Frequency is sufficient to detect abnormal degradation based on industry operating experience.

REFERENCES

1. 10 CFR 50, Appendix A.
2. 10 CFR 50.46.
3. UFSAR, Section 6.2.
4. UFSAR, Chapter 14.
5. NRC Memorandum to V. Stello, Jr., from R.L. Baer, "Recommended Interim Revisions to LCOs for ECCS Components," December 1, 1975.
6. IE Information Notice No. 87-01.

BASES

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to inoperable ECCS High Head Safety Injection subsystems when entering MODE 4. There is an increased risk associated with entering MODE 4 from MODE 5 with an inoperable ECCS high head subsystems and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1

With no ECCS RHR subsystem OPERABLE, the plant is not prepared to respond to a loss of coolant accident or to continue a cooldown using the RHR pumps and heat exchangers. The Completion Time of immediately to initiate actions that would restore at least one ECCS RHR subsystem to OPERABLE status ensures that prompt action is taken to restore the required cooling capacity. Normally, in MODE 4, reactor decay heat is removed from the RCS by an RHR loop. If no RHR loop is OPERABLE for this function, reactor decay heat must be removed by some alternate method, such as use of the steam generators. The alternate means of heat removal must continue until the inoperable RHR loop components can be restored to operation so that decay heat removal is continuous.

With both RHR pumps and heat exchangers inoperable, it would be unwise to require the plant to go to MODE 5, where the only available heat removal system is the RHR. Therefore, the appropriate action is to initiate measures to restore one ECCS RHR subsystem and to continue the actions until the subsystem is restored to OPERABLE status.

B.1

With one of the two required ECCS HHSI subsystems inoperable, the remaining HHSI subsystem and the RHR subsystem maintain substantial capability for the mitigation of a large spectrum of both large and small break LOCAs in Mode 4. Therefore, a Completion Time of 48 hours for restoration of the inoperable subsystem is warranted.

BASES

ACTIONS (continued)

C.1

With no ECCS HHSI subsystem OPERABLE, due to the inoperability of the pump or flow path from the RWST, the plant is not prepared to provide high pressure response to Design Basis Events requiring SI. The 1 hour Completion Time to restore at least one ECCS HHSI subsystem to OPERABLE status ensures that prompt action is taken to provide the required cooling capacity or to initiate actions to place the plant in MODE 5, where an ECCS subsystem is not required.

D.1

When the Required Actions of Conditions B or C cannot be completed within the required Completion Time, a controlled shutdown should be initiated. Twenty-four hours is a reasonable time, based on operating experience, to reach MODE 5 in an orderly manner and without challenging plant systems or operators.

SURVEILLANCE REQUIREMENTS

SR 3.5.3.1

The applicable Surveillance descriptions from Bases 3.5.2 apply.

REFERENCES

The applicable references from Bases 3.5.2 apply.

BASES

BACKGROUND (continued)

b. Sufficient water volume exists in the recirculation or containment sump to support continued operation of the ECCS pumps at the time of transfer to the recirculation mode of cooling, and

c. The reactor remains subcritical following a LOCA.

Insufficient water in the RWST could result in insufficient cooling capacity when the transfer to the recirculation mode occurs. Improper boron concentrations could result in a reduction of SDM or excessive boric acid precipitation in the core following the LOCA, as well as excessive caustic stress corrosion of mechanical components and systems inside the containment due to improper pH in the sumps.

APPLICABLE SAFETY ANALYSES

During accident conditions, the RWST provides a source of borated water to the ECCS and Containment Spray System pumps. As such, it provides containment cooling and depressurization, core cooling, and replacement inventory and is a source of negative reactivity for reactor shutdown (Ref. 1). The design basis transients and applicable safety analyses concerning each of these systems are discussed in the Applicable Safety Analyses section of B 3.5.2, "ECCS - Operating," B 3.5.3, "ECCS - Shutdown," and B 3.6.6, "Containment Spray and Containment Fan Cooler Unit (FCU) System~~s~~." These analyses are used to assess changes to the RWST in order to evaluate their effects in relation to the acceptance limits in the analyses.

System

The RWST must also meet volume, boron concentration, and temperature requirements for non-LOCA events. The volume is not an explicit assumption in non-LOCA events since the required volume is a small fraction of the available volume. The deliverable volume limit is set by the LOCA and containment analyses. For the RWST, the deliverable volume is different from the total volume contained since, due to the design of the tank, more water can be contained than can be delivered. The minimum boron concentration is an explicit assumption in the main steam line break (MSLB) analysis to ensure the required shutdown capability. The maximum temperature ensures that the amount of cooling provided from the RWST is consistent with safety analysis assumptions; the minimum is an assumption in both the MSLB and inadvertent ECCS actuation analyses, although the inadvertent ECCS actuation event is typically nonlimiting.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The IP2 ESFAS design does not include automatic switchover from the safety injection mode to the recirculation mode of operation based on low level in the RWST coincident with a safety injection signal. This function is performed manually by the operator who must be alerted by redundant alarms that annunciate RWST level low low. The switchover to the cold leg recirculation phase is manually initiated when the RWST level has reached the low low alarm setpoint and sufficient coolant inventory to support pump operation in recirculation mode is verified to be in the containment.

The RWST level low low alarm setpoint has both upper and lower limits. The upper limit is set to ensure that switchover does not occur until there is adequate water inventory in the containment to provide ECCS pump suction. (This is confirmed by recirculation and/or containment sump level indication.) The lower limit is set to ensure switchover occurs before the RWST empties, to prevent ECCS pump damage.

Requiring 2 channels of RWST level low low alarm ensures that the alarm function will be available assuming a single failure of one channel.

The RWST satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The RWST ensures that an adequate supply of borated water is available to cool and depressurize the containment in the event of a Design Basis Accident (DBA), to cool and cover the core in the event of a LOCA, to maintain the reactor subcritical following a DBA, and to ensure adequate level in the recirculation and containment sump to support ECCS operation in the recirculation mode.

To be considered OPERABLE, the RWST must meet the water volume, boron concentration, and temperature limits established in the SRs.

RWST Operability requires Operability of two channels of the RWST level low low alarm. This is required because the IP2 ESFAS design does not include automatic switchover from the safety injection mode to the recirculation mode of operation based on low level in the RWST coincident with a safety injection signal. This function is performed manually by the operator who must be alerted by redundant alarms that annunciate RWST level low low. The switchover to the cold leg recirculation phase is manually initiated when the RWST level has reached the low low alarm setpoint and sufficient coolant inventory to support pump operation in recirculation mode is verified to be in the containment.

BASES

APPLICABILITY

In MODES 1, 2, 3, and 4, RWST OPERABILITY requirements are dictated by ECCS and Containment Spray System OPERABILITY requirements. Since both the ECCS and the Containment Spray System must be OPERABLE in MODES 1, 2, 3, and 4, the RWST must also be OPERABLE to support their operation. Core cooling requirements in MODE 5 are addressed by LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled," and LCO 3.4.8, "RCS Loops - MODE 5, Loops Not Filled." MODE 6 core cooling requirements are addressed by LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level," and LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level."

4

5

ACTIONS

A.1

With RWST boron concentration or borated water temperature not within limits of SR 3.5.4.3 or SR 3.5.4.1, respectively, they must be returned to within limits within 8 hours. Under these conditions neither the ECCS nor the Containment Spray System can perform its design function. Therefore, prompt action must be taken to restore the tank to OPERABLE condition. The 8 hour limit to restore the RWST temperature or boron concentration to within limits was developed considering the time required to change either the boron concentration or temperature and the fact that the contents of the tank are still available for injection.

B.1

Condition B applies when one channel of the RWST level low low alarm is inoperable. Required Action B.1 requires restoring the inoperable channel to OPERABLE status within 7 days. The 7 day Completion Time for restoration of redundancy to the alarm function is needed because the IP2 ESFAS design does not include automatic switchover from the safety injection mode to the recirculation mode of operation based on low level in the RWST coincident with a safety injection signal. This function is performed manually by the operator who is alerted by the RWST level low low alarm as the primary indicator for determining the time for the switchover. The 7 day Completion Time for restoration of redundancy for this alarm function is acceptable because of the remaining alarm channel and the availability of containment and recirculation sump level indication in the control room.

BASES

ACTIONS (continued)

C.1

or both RWST level alarms inoperable

With the RWST inoperable for reasons other than Condition A or B (e.g., water volume not within limit of SR 3.5.4.2), it must be restored to OPERABLE status within 1 hour.

In this Condition, neither the ECCS nor the Containment Spray System can perform its design function. Therefore, prompt action must be taken to restore the tank to OPERABLE status or to place the plant in a MODE in which the RWST is not required. The short time limit of 1 hour to restore the RWST to OPERABLE status is based on this condition simultaneously affecting redundant trains.

D.1 and D.2

If the RWST cannot be returned to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.5.4.1

The RWST borated water temperature should be verified every 24 hours to be within the limits assumed in the accident analyses band. This Frequency is sufficient to identify a temperature change that would approach either limit and has been shown to be acceptable through operating experience.

SR 3.5.4.2

The RWST water volume should be verified every 7 days to be above the required minimum level in order to ensure that a sufficient initial supply is available for injection and containment spray and to support continued ECCS operation on recirculation. Since the RWST volume is normally stable and is protected by an alarm, a 7 day Frequency is appropriate and has been shown to be acceptable through operating experience.

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. ----- - NOTE - Only applicable to penetration flow paths with two or more containment isolation valves. ----- One or more penetration flow paths with one containment isolation valve inoperable for reasons other than Condition D.	A.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured.	4 hours
	<u>AND</u>	
	SPACE	
	A.2 ----- - NOTES - 1. Isolation devices in high radiation areas may be verified by use of administrative means. 2. Isolation devices that are locked, sealed, or otherwise secured may be verified by use of administrative means. -----	
	Verify the affected penetration flow path is isolated.	Once per 31 days for isolation devices outside containment <u>AND</u> Prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days for isolation devices inside containment

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. - NOTE - Only applicable to penetration flow paths with two or more containment isolation valves. One or more penetration flow paths with two or more containment isolation valves inoperable for reasons other than Condition D.	B.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	4 hours
C. - NOTE - Only applicable to penetration flow paths with only one containment isolation valve and a closed system. One or more penetration flow paths with one containment isolation valve inoperable.	C.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange. AND (Try to prevent C.2 from rolling over.)	72 hours

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3 Containment Isolation Valves

(CIVs)

BASES

BACKGROUND

The containment isolation valves form part of the containment pressure boundary and provide a means for fluid penetrations not serving accident consequence limiting systems to be provided with two isolation barriers that are closed on a containment isolation signal. These isolation devices are either passive or active (automatic). Manual valves, de-activated automatic valves secured in their closed position (including check valves with flow through the valve secured), blind flanges, and closed systems are considered passive devices. Check valves, or other automatic valves designed to close without operator action following an accident, are considered active devices. Two barriers in series are provided for each penetration so that no single credible failure or malfunction of an active component can result in a loss of isolation or leakage that exceeds limits assumed in the safety analyses. One of these barriers may be a closed system. These barriers (typically containment isolation valves) make up the Containment Isolation System.

Automatic isolation signals are produced during accident conditions. Containment Phase "A" isolation occurs upon receipt of a safety injection signal. The Phase "A" isolation signal isolates nonessential process lines in order to minimize leakage of fission product radioactivity. Containment Phase "B" isolation occurs upon receipt of a containment pressure High-High signal and isolates the remaining process lines, except systems required for accident mitigation. In addition to the isolation signals listed above, the containment purge supply and exhaust isolation valves and the containment pressure relief line isolation valves receive an isolation signal on a containment high radiation condition or manual signal as required by LCO 3.3.6, "Containment Purge System and Pressure Relief Line Isolation Instrumentation." Additionally, a high radiation signal from the monitor in the plant vent will also isolate the containment purge system and pressure relief line. As a result, the containment isolation valves (and blind flanges) help ensure that the containment atmosphere will be isolated from the environment in the event of a release of fission product radioactivity to the containment atmosphere as a result of a Design Basis Accident (DBA).

The OPERABILITY requirements for containment isolation valves help ensure that containment is isolated within the time limits assumed in the safety analyses. Therefore, the OPERABILITY requirements provide assurance that the containment function assumed in the safety analyses will be maintained.

BASES

BACKGROUND (continued)

Containment Purge Supply and Exhaust Isolation Valves

The containment purge system is independent of the primary auxiliary building exhaust system, (except for the common exhaust fans) and includes provisions for both supply and exhaust air. The supply system includes roughing filters, heating coils, fan, supply penetration with two 36 inch butterfly valves for isolation, and a purge supply distribution header inside containment. The exhaust system includes exhaust penetration with two 36 inch butterfly valves, exhaust ductwork, filter bank with roughing, HEPA and charcoal filters, fans and exhaust vent. The design full purge flow rate is 25,000 cfm.

The containment purge system isolation valves are not normally opened when in MODES 1, 2, 3 and 4 because containment pressure control is provided by the containment pressure relief line. However, containment purge system isolation valves may be opened, as needed, for pressure control, ALARA or air quality considerations for personnel entry, or for Surveillances that require the valves to be open. This is acceptable because the containment purge supply duct and exhaust duct are each equipped with two solenoid-controlled, pneumatically operated butterfly valves (one inside and one outside of the containment) to be used for isolation purposes. The valves are automatically closed upon receipt of a safety injection signal or high-containment radiation signal and are spring-loaded to fail closed on loss of control signal or instrument air. Valve travel is limited to a maximum of 60 degrees to ensure that the valves will be able to close against the maximum calculated design-basis accident pressure of 47 psig. An adjustable position setting on the actuators allows the valves to be opened to a full 90-degree position when containment integrity is not required.

When the containment purge system isolation valves are closed, the space between each set of valves is pressurized above containment design pressure from the ~~Weld Channel and Penetration Pressurization System~~ WC&PPS in accordance with LCO 3.6.10, "Weld Channel and Penetration Pressurization System (WC&PPS)."

Containment Pressure Relief Line Isolation Valves

The normal pressure changes in the containment during reactor power operation, and during plant cooldown are handled by the containment pressure relief line. Because the line is intended to be opened periodically during reactor power operation, three 10 inch butterfly valves in series are provided for isolation, one inside and two outside the containment. The design and operation of these valve s is similar to the containment purge

BASES

BACKGROUND (continued)

supply and exhaust isolation valves. The valves are automatically closed upon receipt of a safety injection signal or high-containment radiation signal and are equipped with an accumulator to assure each valve can close even if the air supply is lost. Valve travel is limited to a maximum of 60 degrees to ensure that the valves will be able to close against the maximum calculated design-basis accident pressure of 47 psig.

WC&PPS

When the containment pressure relief line isolation valves are closed, the two spaces between the three valves is pressurized above containment design pressure from the ~~Weld Channel and Penetration Pressurization System~~ in accordance with LCO 3.6.10, "Weld Channel and Penetration Pressurization System (WC&PPS)".

APPLICABLE SAFETY ANALYSES

The containment isolation valve LCO was derived from the assumptions related to establishing the containment boundary during major accidents. As part of the containment boundary, containment isolation valve OPERABILITY supports leak tightness of the containment. Therefore, the ~~safety analyses~~ of any event requiring isolation of containment is applicable to this LCO.

The DBAs that result in a release of radioactive material within containment are a loss of coolant accident (LOCA) and a rod ejection accident (Ref. 1). In the analyses for each of these accidents, it is assumed that containment isolation valves are either closed or function to close within the required isolation time following event initiation. This ensures that potential paths to the environment through containment isolation valves (including containment purge valves) are minimized. The containment purge (supply and exhaust) and the containment pressure relief line may be opened in MODES 1, 2, 3 and 4, as needed, for pressure control, ALARA or air quality considerations for personnel entry, or for Surveillances that require the valves to be open. This is acceptable because the containment purge (supply and exhaust) and the containment pressure relief line are each equipped with redundant containment isolation valves that are automatically closed upon receipt of a safety injection signal or high-containment radiation signal in containment.

The DBA analysis assumes that, within 60 seconds after the accident, isolation of the containment is complete and leakage terminated except for the design leakage rate, L_a. The containment isolation total response time of 60 seconds includes signal delay, diesel generator startup (for loss of offsite power), and containment isolation valve stroke times.

BASES

ACTIONS (continued)

isolation boundary and the relative importance of maintaining containment integrity during MODES 1, 2, 3, and 4. In the event the affected penetration flow path is isolated in accordance with Required Action C.1, the affected penetration flow path must be verified to be isolated on a periodic basis. This periodic verification is necessary to assure leak tightness of containment and that containment penetrations requiring isolation following an accident are isolated. The Completion Time of once per 31 days for verifying that each affected penetration flow path is isolated is appropriate because the valves are operated under administrative controls and the probability of their misalignment is low.

Condition C is modified by a Note indicating that this Condition is only applicable to those penetration flow paths with only one containment isolation valve and a closed system. The closed system must meet the requirements of Ref. 3. This Note is necessary since this Condition is written to specifically address those penetration flow paths in a closed system.

Required Action C.2 is modified by two Notes. Note 1 applies to valves and blind flanges located in high radiation areas and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned. Therefore, the probability of misalignment of these valves, once they have been verified to be in the proper position, is small.

<u>D.1</u>

With the hydrostatically tested valve leakage not within limit of SR 3.6.3.9 the potential exists for flooding the Containment Recirculation Pumps during long term post-accident cooling. The leakage must be restored to within limits. Restoration can be accomplished by isolating the penetration(s) that caused the limit to be exceeded by use of one closed and de-activated automatic valve, closed manual valve, or blind flange. When a penetration is isolated the leakage rate for the isolated penetration is assumed to be the actual pathway leakage through the isolation device. If two isolation devices are used to isolate the penetration, the leakage rate is assumed to be the

BASES

SURVEILLANCE REQUIREMENTS (continued)

Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 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 that these components usually pass this Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.3.7

Verifying that each containment purge supply and exhaust isolation valves (FCV-1170, FCV-1171, FCV-1172, and FCV-1173) and the containment pressure relief line isolation valves (PCV-1190, PCV-1191 and PCV-1192) is blocked to restrict opening to ≤ 60 degrees is required to ensure that the valves can close under DBA conditions within the times assumed in the analyses of References 1 and 2. If a LOCA occurs, the purge valves must close to maintain containment leakage within the values assumed in the accident analysis. At other times when purge valves are ~~not~~ required to be capable of closing (e.g., during movement of recently irradiated fuel assemblies), pressurization concerns are not present, thus the purge valves can be fully open. The 24 month Frequency is appropriate because the blocking devices are typically removed only during a refueling outage.

SR 3.6.3.8

Technical Specification 5.5.14, Containment Leakage Rate Testing Program, includes a limit for the inleakage into containment from the containment isolation valves sealed with service water. The maximum permissible inleakage rate of 0.36 gpm per fan-cooler from the containment isolation valves sealed with service water is intended to prevent flooding the internal recirculation pumps during the full 12-month post-accident recirculation period. The results for this inleakage test are not counted against the acceptance criteria for the Type B and C tests that are also performed as part of the SR. The Frequency for this SR is specified in Technical Specification 5.5.14 and is based on operating experience and the plant conditions necessary to perform this test.

REFERENCES

1. UFSAR, Section 14.

2. UFSAR, Section 5.

BASES

REFERENCES (continued)

3. Standard Review Plan 6.2.4.

4. Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Amendment No. 211 to Facility Operating License No. DPR-26, July 27, 2000.

5. Generic Issue B-24

L.5 3.6.3: Containment Isolation Valves

Rev. 0 Category Less Restrictive (Cat V): Relaxation of LCO Requirement

DOC Summary:

Expands conditions that allow opening the containment purge supply and exhaust isolation valves and the pressure relief line isolation valves from "containment pressure control, or to facilitate safety-related surveillance or safety-related maintenance" to "pressure control, ALARA or air quality considerations for personnel entry, or for Surveillances that require the valves to be open."

Description of Change

CTS 3.6.A.2 specifies that the containment purge supply and exhaust isolation valves and the pressure relief line isolation valves "may only be open for safety related reasons." CTS 3.6.A.2 (Note 1) clarifies that safety related reasons include "include containment pressure control, or to facilitate safety-related surveillance or safety-related maintenance."

ITS SR 3.6.3.1 and ITS SR 3.6.3.2 maintain the restrictions for opening the containment purge supply and exhaust isolation valves and the pressure relief line isolation valves; however, ITS 3.6.3 allows these valves to be open for pressure control, ALARA or air quality considerations for personnel entry, or for Surveillances that require the valves to be open.

Justification for Change

This change is needed and is acceptable because ITS SR 3.6.3.1 and ITS SR 3.6.3.2 allow the valves to be open only as needed to satisfy their design function. Additionally, the containment purge supply duct and exhaust ducts and the containment pressure relief line are each equipped with redundant automatic containment isolation valves. The valves are automatically closed upon receipt of ESFAS signal or high-containment radiation signal and are spring-loaded to fail closed on loss of control signal or instrument air. Valve travel is limited to a maximum of 60 degrees to ensure that the valves will be able to close against the maximum calculated design-basis accident pressure of 47 psig. Additionally, there is a low probability of an event during the limited period of time that the valves are open.

L.6 didn't print

BASES

LCO

The initial containment average air temperature must be maintained less than or equal to the upper LCO temperature limit to ensure the resultant peak accident temperature is maintained below the containment design temperature during a DBA. As a result, the ability of containment to perform its design function is ensured.

The LCO limits for containment temperature are analytical limits. Therefore, an appropriate allowance for instrument uncertainty must be applied when ensuring these limits are met.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining containment average air temperature within the limits is not required in MODE 5 or 6.

ACTIONS

A.1

When containment average air temperature is not within the limits of the LCO, it must be restored to within limit (s) within 8 hours. This Required Action is necessary to return operation to within the bounds of the containment analysis. The 8 hour Completion Time is acceptable considering the sensitivity of the analysis to variations in this parameter and provides sufficient time to correct minor problems.

B.1 and B.2

If the containment average air temperature cannot be restored to within its limits within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES

BACKGROUND (continued)

iodine removal during the containment recirculation phase. In this configuration, the RHR heat exchangers provide the necessary cooling of the recirculated containment spray.

The Containment Spray System provides a spray of cold borated water into the upper regions of containment to reduce the containment pressure and temperature and to reduce fission products from the containment atmosphere during a DBA. The RWST solution temperature is an important factor in determining the heat removal capability of the Containment Spray System during the injection phase. In the recirculation mode of operation, heat is removed from the recirculation sump or the containment sump water by the residual heat removal coolers. Both trains of the Containment Spray System provides adequate spray to meet the system design requirements for containment heat removal even if the Fan Cooler System is not operable.

The recirculation system pH control system will add trisodium phosphate to the sump when the level of the boric acid solution from the containment spray and the coolant lost from the reactor coolant system rises above the level of the trisodium phosphate baskets in containment. The resulting alkaline pH of the spray enhances the ability of the re-circulated spray to scavenge fission products from the containment atmosphere. The trisodium phosphate also ensures an alkaline pH for the solution recirculated in the containment sump. The alkaline pH of the recirculation sump or the sump water minimizes the evolution of iodine and minimizes the occurrence of chloride and caustic stress corrosion on mechanical systems and components exposed to the fluid.

The Containment Spray System is actuated either automatically by a containment High-High pressure signal or manually. An automatic actuation starts the two containment spray pumps, opens the containment spray pump discharge valves, and begins the injection phase. A manual actuation of the Containment Spray System requires the operator to actuate two separate push buttons on the main control board to begin the same sequence. The injection phase continues until the RWST water supply is exhausted. After the Refueling Water Storage Tank has been exhausted, the containment recirculation pumps or the Residual Heat Removal (RHR) pumps may be used to supply the Containment Spray ring headers for the long-term containment cooling and iodine removal during the containment recirculation phase. In this configuration, the RHR heat exchangers provide the necessary cooling of the recirculated containment spray. The Containment Spray System in the recirculation mode may be used to maintain an equilibrium temperature between the containment atmosphere and the

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.6.9

This SR verifies that minimum air flow through each FCU equals the air flow assumed in the accident analysis for heat removal from the containment. The 24 month Frequency is based on engineering judgement.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 38, GDC 39, GDC 40, GDC 41, GDC 42, and GDC 43.
2. 10 CFR 50, Appendix K.
3. UFSAR, Section 6.3.
4. UFSAR, Section 6.4.
5. UFSAR, Section 14.3.
6. ASME, Boiler and Pressure Vessel Code, Section XI.
7. Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Amendment No. 211 to Facility Operating License No. DPR-26, July 27, 2000.

3.6 CONTAINMENT SYSTEMS

3.6.7 Recirculation pH Control System

LCO 3.6.7 The Recirculation pH Control System shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

Restore

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Recirculation pH Control System inoperable.	A.1	Recirculation pH Control System to OPERABLE status.	72 hours
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 3.	6 hours
	AND		
	B.2	Be in MODE 5.	84 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.7.1	Perform a visual inspection of the four trisodium phosphate storage baskets to verify each of the following: a. Each storage basket is in place and intact; and, b. Collectively contain ≥ 8000 pounds (148 cubic feet) of trisodium phosphate (w/12 hydrates), or equivalent.	24 months

B 3.6 CONTAINMENT SYSTEMS

B 3.6.7 Recirculation pH Control System

BASES

BACKGROUND

The recirculation ~~fluid~~ pH control system is a passive safeguard with baskets of trisodium phosphate located in the containment sump area. Trisodium phosphate is stored in four baskets at the 46 foot elevation inside the containment building (Ref. 1).

During the injection phase the level of the boric acid solution from the containment spray and the coolant lost from the reactor coolant system will rise above the trisodium phosphate baskets. The trisodium phosphate will dissolve into the solution, providing a solution with pH in the range of 7 to 9.5 to enhance long-term iodine retention in the solution and to minimize corrosion (Ref. 1).

Section 6.5.2 of the Standard Review Plan (Ref. 3) specifies a pH value greater than or equal to 7.0 to assure continued retention of iodine in the sump solution. WCAP-14542, "Evaluation of the Radiological Consequences from a Loss of Coolant Accident at IP2 Using NUREG-1465 Source Term Methodology," dated July 1996 (Ref. 4), states that, for IP2, the mass of trisodium phosphate (TSP) required to provide an equilibrium sump solution pH of 7.0 is less than 4,000 pounds. To address the potential for long term generation of acids in the containment, this amount is doubled to 8,000 pounds. The initial containment spray will be boric acid solution from the refueling water storage tank which has a pH of approximately 4.5. As the initial spray solution and, subsequently, the recirculation solution comes in contact with the TSP, the TSP dissolves raising the pH of the sump solution to an equilibrium value between 7.0 and 9.5 (Ref. 5).

APPLICABLE SAFETY ANALYSES

The recirculation ~~fluid~~ pH control system is a passive safeguard with the baskets of trisodium phosphate located in the containment sump area. The OPERABILITY of the recirculation ~~fluid~~ pH control system ensures that there is sufficient trisodium phosphate (TSP) available in containment to guarantee a sump pH >7.0 during the recirculation phase of a postulated LOCA. The mass of trisodium phosphate (TSP) required to provide an equilibrium sump solution pH of 7.0 is less than 4,000 pounds. To address the potential for long term generation of acids in the containment, this amount is doubled to 8,000 pounds. The initial containment spray will be

BASES

APPLICABLE SAFETY ANALYSES (continued)

boric acid solution from the refueling water storage tank which has a pH of approximately 4.5. As the initial spray solution and, subsequently, the recirculation solution comes in contact with the TSP, the TSP dissolves raising the pH of the sump solution to an equilibrium value between 7.0 and 9.5 (Ref. 5).

The Recirculation pH Control System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The recirculation ~~fluid~~ pH control system is necessary to reduce the release of radioactive material to the environment in the event of a DBA. To be considered OPERABLE, each of the four storage trisodium baskets must be in place and intact and collectively contain ≥ 8000 pounds (148 cubic feet) of trisodium phosphate (w/12 hydrates), or equivalent.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment requiring the operation of the recirculation pH control system. The recirculation pH control system assists in reducing the iodine fission product inventory prior to release to the environment.

In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Thus, the recirculation pH control system is not required to be OPERABLE in MODE 5 or 6.

ACTIONS

A.1

If the recirculation pH control system is inoperable, it must be restored to OPERABLE within 72 hours. The pH adjustment of the recirculation pH control system flow for corrosion protection and iodine removal enhancement is reduced in this condition. The Containment Spray system would still be available and would remove some iodine from the containment atmosphere in the event of a DBA (Ref. 6). The 72 hour Completion Time takes into account the low probability of the worst case DBA occurring during this period.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.10.1

This SR requires periodic verification during plant operation that the required portions of each WC&PPS zone are maintained at a pressure greater than the containment peak accident pressure. This SR is satisfied by verification of zone pressure on each of the four WC&PPS zones is above the specified limit. The 31 day Frequency is acceptable because there are low pressure alarms in the Control Room to ensure that operators are aware that all WC&PPS zones are pressurized.

SR 3.6.10.2

This SR requires periodic verification during plant operation that the WC&PPS air consumption is ≤ 0.2% of the containment free volume per day. This SR is performed by taking the sum of the reading on the flow sensing devices located in each of the zone headers. A WC&PPS total flow rate of 44.4 scfm, if sustained for 24 hours, is equivalent to 0.2% of the containment free volume at a pressure of 47 psig. The 31 day Frequency recognizes that WC&PPS air consumption indication and high flow alarms are provided in the control room.

15.2

DBP project comment

SR 3.6.10.3

This SR, sometimes called the sensitive leak rate test, ensures that the leakage rate for the WC&PPS is ≤ 0.2% of the containment free volume per day when pressurized to ≥ 52 psig above containment pressure. The sensitive leak rate test includes only the volume of the weld channels, double penetrations, and containment isolation valves supported by WC&PPS. This test is considered more sensitive than the integrated leakage rate test, as the instrumentation used permits a direct measurement of leakage from the pressurized zones. The 24 month Frequency is acceptable because experience has shown that the WC&PPS usually passes this Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. UFSAR, Section 6.6.
2. 10 CFR 50.67.
3. Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Amendment No. 211 to Facility Operating License No. DPR-26, July 27, 2000.

BASES

ACTIONS (continued)

The maximum THERMAL POWER corresponding to the heat removal capacity of the remaining OPERABLE MSSVs is determined via a conservative heat balance calculation as described in the attachment to Reference 6, with an appropriate allowance for Nuclear Instrumentation System trip channel uncertainties.

Protection

Required Action B.2 is modified by a Note, indicating that the Power Range Neutron Flux-High reactor trip setpoint reduction is only required in MODE 1. In MODES 2 and 3 the reactor protection system trips specified in LCO 3.3.1, "Reactor Trip System Instrumentation," already establish a trip setpoint lower than that required by this LCO.

The allowed Completion Times are reasonable based on operating experience to accomplish the Required Actions in an orderly manner without challenging unit systems.

C.1 and C.2

If the Required Actions are not completed within the associated Completion Time, or if one or more steam generators have ≥ 4 inoperable MSSVs, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 12 hours. The allowed Completion Times are 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 3.7.1.1

This SR verifies the OPERABILITY of the MSSVs by the verification of each MSSV lift setpoint in accordance with the Inservice Testing Program. The ASME Code, Section XI (Ref. 4), requires that safety and relief valve tests be performed in accordance with ANSI/ASME OM-1-1987 (Ref. 5). According to Reference 5, the following tests are required:

a. Visual examination,

b. Seat tightness determination,

c. Setpoint pressure determination (lift setting), and

d. Compliance with owner's seat tightness criteria.

BASES

ACTIONS (continued)

function to mitigate the failure of an MSIV associated with any of the other SGs. Additionally, an inoperable MSCV does not affect the consequences of an SLB downstream of the MSIV.

The 72 hour Completion Time is acceptable because of the following: all MSIVs are Operable, there is a low probability of the failure of an MSIV during the 72 hour period that one or more MSCVs are inoperable; and, there is a low probability of an accident that would require a closure of the MSCVs or MSIVs during this period.

B.1 and B.2

If the MSCV cannot be restored to OPERABLE status within 72 hours, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in MODE 2 within 6 hours and all MSIVs must be closed within 14 hours. The Completion Times are reasonable, based on operating experience, to reach MODE 2 and to close the MSIVs ~~or complete a plant cooldown to MODE 4~~ in an orderly manner and without challenging unit systems.

C.1

With one MSIV inoperable in MODE 1, action must be taken to restore OPERABLE status within 72 hours. Some repairs to the MSIV can be made with the unit hot. The 72 hour Completion Time for restoration of an inoperable MSIV is acceptable because the plant remains within the SGTR and SLB accident analysis assumptions (including assumptions regarding single failure of an MSIV) except for an SLB that occurs downstream of the MSIVs. For an SLB that occurs downstream of the MSIVs, IP2 remains within the accident analysis assumptions except for the ability to tolerate the random failure of a second MSIV during the 72 hour allowable out of service time for the one MSIV permitted to be inoperable.

D.1

If the MSIV cannot be restored to OPERABLE status within 72 hours, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in MODE 2 within 6 hours and Condition E would be entered. The Completion Times are reasonable, based on operating experience, to reach MODE 2 and to close the MSIVs in an orderly manner and without challenging unit systems.

BASES

ACTIONS (continued)

E.1 and E.2

Condition E is modified by a Note indicating that separate Condition entry is allowed for each MSIV.

Since the MSIVs are required to be OPERABLE in MODES 2 and 3, the inoperable MSIVs may either be restored to OPERABLE status or closed. When closed, the MSIVs are already in the position required by the assumptions in the safety analysis.

The 8 hour Completion Time is reasonable, based on operating experience, to close the MSIVs after reaching MODE 2~~, or complete a plant cooldown to MODE 4 in an orderly manner and without challenging unit systems.~~

For inoperable MSIVs that cannot be restored to OPERABLE status within the specified Completion Time, but are closed, the inoperable MSIVs must be verified on a periodic basis to be closed. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of MSIV status indications available in the control room, and other administrative controls, to ensure that these valves are in the closed position.

F.1 and F.2

If one MSIV is inoperable when one or more MSCVs are inoperable, then more than one SG may blowdown following an SLB upstream of an MSIV and the plant is outside of the analysis assumptions. The plant remains within the analysis assumptions for an SLB downstream of an MSIV although the ability to tolerate the failure if a second MSIV is lost. In this condition, all MSCVs must be restored to OPERABLE status or all MSIVs must be restored to OPERABLE status within 1 hour. The 1 hour Completion Time is acceptable because of the low probability of an accident that would require a closure of the MSCVs or MSIVs during this time period.

G.1 and G.2

If the MSIVs or MSCVs cannot be restored to OPERABLE status or are not closed within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed at least in MODE 3 within 6 hours, and in MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from MODE 2 conditions in an orderly manner and without challenging unit systems.

B 3.7 PLANT SYSTEMS

B 3.7.3 Main Feedwater Isolation

BASES

BACKGROUND

Isolation of the main feedwater system is necessary to mitigate various accident and transient conditions (main steamline breaks, steam generator tube ruptures, and excessive heat removal due to feedwater system malfunction). Main feedwater must be automatically isolated to prevent excessive Reactor Coolant System (RCS) cooldown, containment overpressure, and steam generator overfill. Main feedwater isolation is initiated by either an ESFAS safety injection (SI) signal or high steam generator water level. Main feedwater isolation to all four steam generators is provided by either of the following:

a. Closure of all four Main Feedwater Regulating Valves (MFRVs) and closure of all four Low Flow Main Feedwater Bypass Valves (FBVs); or,

b. Closure of both Main Boiler Feedwater Pump (MBFP) discharge valves which initiates closure of all eight Main Feedwater Isolation Valves (MFIVs), and the trip of both Main Boiler Feedwater Pumps (MBFPs).

Either of these combinations is capable of achieving main feedwater isolation to all four steam generators within the time limits assumed in the accident analysis. Note that closure of the eight MFIVs is not required to meet accident analysis assumptions.

Main feedwater isolation is initiated by a safety injection ESFAS signal or a high steam generator water level ESFAS signal either of which provides a direct signal that closes all four MFRVs within 8 seconds and all four Lo Flow FBVs within 15 seconds. If all eight of these valves close, main feedwater isolation to all four SGs is completed within time limits that satisfy accident analysis assumptions (Ref. ~~1~~ 2).

To establish required redundancy for the main feedwater isolation safety function, the safety injection ESFAS signal or high steam generator water level ESFAS signal also provides a direct signal that closes the two MBFP discharge valves within 60 seconds. Although closure of the MBFP discharge valves provides complete isolation of main feedwater to all four SGs, closure of the MBFP discharge valves does not satisfy accident analysis assumptions. Therefore, when the MBFP discharge valves close in response to an ESFAS signal, the main boiler feed pump will automatically trip when the associated MBFP discharge valve moves off the open seat.

BASES

BACKGROUND (continued)

MBFP discharge valves closure and the MBFP trip are sufficient to satisfy accident analysis assumptions for peak containment pressure. However, this barrier does not isolate the SGs and containment from the significant amount of feedwater mass and energy in the three high pressure feedwater heaters and the feedwater piping located between the MBFP discharge valves and the SGs. Therefore, when both MBFP discharge valves move off the open seat, a signal is generated that initiates closure of the eight Main Feedwater Isolation Valves (MFIVs). The eight MFIVs are motor operated valves that are located near to and isolate the four MFRVs and the four Lo Flow FBVs. The MBFP trip occurs within 5 seconds and closure of the MFIVs occurs within 120 seconds of the ESFAS signal that initiated closure of the MBFP discharge valve. Although not required to satisfy accident analysis assumptions, closure of the eight MFIVs conservatively limits peak containment pressure following an SLB or excess feedwater event. The eight MFIVs are the following: four motor operated MFRV isolation valves (BFD-5, BFD-5-1, BFD-5-2 and BFD-5-3), and four motor operated Lo Flow FBVs isolation valves (BFD-90, BFD-90-1, BFD-90-2 and BFD-90-3).

In addition to the MFRVs, Lo Flow FBVs and the MSIVs, the main feedwater line and auxiliary feedwater line to each SG includes a check valve that is located outside containment. These check valves provide a pressure boundary that allows either the main feedwater system or auxiliary feedwater system to supply an SG and prevent blowdown of a SG if main and auxiliary feedwater pressure is lost.

The main feedwater isolation safety function and components are described in References 1 and ~~3~~ 2

APPLICABLE SAFETY ANALYSES

The design basis of the main feedwater isolation function is established by the analyses for the large SLB. Main feedwater isolation may also be relied on to terminate an SLB for core response analysis and excess feedwater event upon the receipt of a steam generator water level - high high signal or a feedwater isolation signal on high steam generator level.

Failure of main feedwater isolation following an SLB can result in additional mass and energy being delivered to the steam generators, contributing to cooldown. This failure also results in additional mass and energy releases following an SLB.

Main feedwater isolation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

ACTIONS (continued)

F.1 and F.2

If the main feedwater isolation safety function and/or required redundancy cannot be restored to OPERABLE status, or affected valves closed, or affected flow paths isolated within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 12 hours. The allowed Completion Times are 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 3.7.3.1 and SR 3.7.3.2

These SRs verify that each of the valves in both of the main feedwater isolation barriers close within the time limits assumed in the accident analysis. SR 3.7.3.1 requires verification that MFRVs and Lo Flow FBVs close within the following limits:

MFRVs (FCV-417, FCV-427, FCV-437, and FCV-447) close in ≤ 8 seconds; and

Lo Flow FBVs (FCV-417L, FCV-427L, FCV-437L, and FCV-447L) close in ≤ 15 seconds.

SR 3.7.3.2 requires verification that MBFP discharge valves ~~and MFIVs close~~ and MBFP trips within the following limits:

MBFP discharge valves (BFD-2-21 and BFD-2-22) close in ≤ 60 seconds; and

MBFPs (BFP 21 and BFP 22) trip in ≤ 5 seconds.

These Surveillances are normally performed upon returning the unit to operation following a refueling outage. These valves should not be tested at power since even a part stroke exercise increases the risk of a valve closure with the unit generating power. This is consistent with the ASME Code, Section XI (Ref. 3), quarterly stroke requirements during operation in MODES 1 and 2.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The Frequency for these SRs is in accordance with the Inservice Testing Program.

SR 3.7.3.3

and MBFP discharge valve

This SR verifies that each MFRV, ~~and~~ Lo Flow FBV will close and that each MBFP will trip on an actual or simulated actuation signal. This Surveillance is normally performed upon returning the plant to operation following a refueling outage.

The Frequency for this SR is every 24 months. The 24 month Frequency for testing is based on the refueling cycle. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, this Frequency is acceptable from a reliability standpoint.

REFERENCES

1. UFSAR, Section 10.2.
2. UFSAR, Section 14.2.
3. ASME, Boiler and Pressure Vessel Code, Section XI.

BASES

APPLICABLE SAFETY ANALYSES (continued)

to cool down the unit, the ADVs and main steam safety valves (MSSVs) are assumed to operate automatically to relieve steam and maintain the steam generator pressure below the design value. For the recovery from a steam generator tube rupture (SGTR) event, the operator is also required to perform a limited cooldown to establish adequate subcooling as a necessary step to terminate the primary to secondary break flow into the ruptured steam generator. The time required to terminate the primary to secondary break flow for an SGTR is more critical than the time required to cool down to RHR conditions for this event and also for other accidents. Thus, the SGTR is the limiting event for the ADVs.

The IP2 analysis of the radiological consequences of a SGTR (References 2 and 3) conservatively assumes no operator actions that would help to terminate the primary to secondary leakage such as controlled depressurization of the RCS to the ruptured steam generator pressure or subsequent termination of safety injection flow to stop primary to secondary leakage. If the operators take no action to respond to the event, the break flow will tend to an equilibrium RCS pressure where incoming safety injection flow is balanced by outgoing break flow. In the accident analysis, this equilibrium break flow is assumed to persist from plant trip until 30 minutes after the accident initiation. The analysis does not require that the operators demonstrate the ability to terminate break flow within 30 minutes from the start of the event. It is recognized that the operators may not be able to terminate break flow within 30 minutes for all postulated SGTR events. The purpose of the calculation is to provide conservatively high mass-transfer rates for use in the radiological consequences analysis. This is achieved by assuming a constant break flow at the equilibrium flow rate for a relatively long time period (i.e., 30 minutes). Because this analysis assumed a loss of offsite power, plant cool down occurs using the ADVs and the steam generator safety valves with the lowest lift setting.

Using the conservative assumptions described above, the radiological consequences analysis were determined assuming both a pre-accident iodine spike (RCS at 60 times the assumed maximum coolant equilibrium concentration limit of 1.0 mCi/gm of DOSE EQUIVALENT I-131) and an accident initiated iodine spike (RCS at the assumed maximum coolant equilibrium concentration limit of 1.0 mCi/gm of DOSE EQUIVALENT I-131).

space

For the pre-accident iodine spike scenario, the exclusion area boundary (EAB) dose is 4.4 rem total effective dose equivalent (TEDE) and the low population zone (LPZ) dose is 2.1 rem TEDE (Ref. 2). These results are well within the 10 CFR 50.67 limits of 25 rem TEDE (Ref. 4).

B 3.7 PLANT SYSTEMS

B 3.7.8 Service Water System (SWS)

BASES

BACKGROUND

The SWS provides a heat sink for the removal of process and operating heat from safety related components during a Design Basis Accident (DBA) or transient. During normal operation, and a normal shutdown, the SWS also provides this function for various safety related and nonsafety related components. The safety related function is covered by this LCO.

The SWS consists of two separate, 100% capacity, safety related, cooling water headers. Each header is supplied by three pumps and includes the pump strainers and the piping up to and including the isolation valves on individual components cooled by the SWS.

SWS heat loads are designated as either essential or non-essential. The essential SWS heat loads are those which must be supplied with cooling water immediately in the event of a LOCA and/or loss of offsite power (LOOP). Examples of essential loads are the diesel generators (DGs) and containment fan cooler units (FCUs). The non-essential SWS heat loads are those which are required following a postulated LOCA only after the switch over to the recirculation phase. The most significant non-essential loads are the component cooling water (CCW) heat exchangers.

The FCUs are connected in parallel to the essential SWS header. Normal SW flow to the FCUs is controlled by TCV-1103. Required ESFAS flow to all five FCUs is initiated when either (or both) of the redundant FCU ESFAS Service Water valves (TCV-1104 and TCV-1105) opens automatically in response to an ESFAS actuation signal.

The DGs are connected in parallel to the essential SWS header. Normal Required ESFAS flow to all three DGs is initiated when either (or both) of the redundant DG ESFAS Service Water valves (FCV-1176 and FCV-1176A) opens automatically in response to an ESFAS actuation which starts the DGs.

Either of the two SWS headers can be aligned to supply the essential heat loads or the non-essential SWS heat loads. Both the essential and non-essential SWS headers are operated to support normal plant operation and the plant response to accidents and transients. The SWS pumps associated with the SWS header designated as the essential header will start automatically. The SWS pumps associated with the SWS header designated as the non-essential header must be manually started when

BASES

APPLICABILITY

In MODES 1, 2, 3, and 4, the SWS is a normally operating system that is required to support the OPERABILITY of the equipment serviced by the SWS and required to be OPERABLE in these MODES.

In MODES 5 and 6, the OPERABILITY requirements of the SWS are determined by the systems it supports.

ACTIONS

STET

The Actions are modified by a Note that specifies that LCO 3.0.3 is not applicable for 8 hours while swapping the essential SWS header with the non-essential SWS header but only if LCO 3.7.8 will be met after the essential and non-essential header are swapped. This means that the essential and non-essential SWS headers may be cross-connected for up to 8 hours during transfer of the designated essential SWS header to the alternate SWS header. This is acceptable because the transfer is performed infrequently (approximately every 90 days) and the low probability of an event while the headers are cross connected.

A.1 and B.1

If one of the three required SWS pumps on the essential SWS header is inoperable (Condition A), three Operable pumps must be restored to the essential SWS header within 72 hours. Likewise, if one of the two required SWS pumps on non-essential SWS header is inoperable (Condition B), the header must be restored so that there are two Operable pumps for the non-essential SWS header within 72 hours. With one required SWS pump inoperable on either or both SWS headers, the remaining OPERABLE SWS pumps are adequate to perform the heat removal function. However, the overall reliability is reduced because a single failure in an OPERABLE SWS pump could result in loss of SWS function. The 72 hour Completion Time is based on the redundant capabilities afforded by the OPERABLE SWS pumps in the same header and the low probability of a DBA occurring during this time period.

C.1 and D.1

Required ESFAS flow to all three DGs is initiated when either of the redundant SW to DG ESFAS valves (FCV-1176 or FCV-1176A) opens automatically in response to an ESFAS actuation which starts the DGs. Similarly, required ESFAS flow to all five FCUs is initiated when either of the redundant SW to FCU ESFAS valves (TCV-1104 or TCV-1105) opens automatically in response to an ESFAS actuation signal. The SW to FCU ESFAS valves and SW to DG ESFAS valves are OPERABLE when they

B 3.7 PLANT SYSTEMS

B 3.7.10 Control Room Ventilation System (CRVS)

BASES

BACKGROUND

The CRVS provides a protected environment from which operators can control the unit following an uncontrolled release of radioactivity.

The Control Room Ventilation System consists of the following:

- A direct expansion air conditioning unit complete with a fan (CCRF-21) and steam heating coil. The design capacity of the unit is 9200 cfm. A backup fan (CCRCF-22) of the same design capacity is installed in parallel with the air conditioning unit;

- A single 2000 cfm filter unit consisting of two high efficiency particulate air (HEPA) filters; two activated charcoal adsorbers for removal of gaseous activity (principally iodines);

separate bullet

- Two 100% capacity (2000 cfm ±10%) filter booster fans (CCRBF-21 and CCRBF-22);

- One locker room and toilet exhaust fan (K-8); and

- A single duct system that uses redundant dampers, controls and associated accessories to provide for three different air flow configurations.

The three CRVS air flow configurations are normal mode, incident 100% recirculation mode, and outside filtered air pressurization mode.

Normal mode (mode 1) for the CRVS is used to provide cooling or heating for the control room atmosphere. In this mode, control room air is recirculated through the air conditioning unit at a rate of approximately 8280 cfm. Outside makeup air is provided to makeup for the approximately 920 cfm that is exhausted through the toilet exhaust fan. In the CRVS normal mode, the HEPA/adsorber filter unit is bypassed.

Pressurization mode (mode 2) for the CRVS is used for protection against airborne radiation. In this mode, the control room is pressurized with outside air that is drawn through the HEPA/adsorber filter unit. Pressurization with filtered air minimizes inleakage of unfiltered air into the control room. This mode is established as follows:

BASES

BACKGROUND (continued)

- A safety injection signal or a high radiation signal from the control room monitor (RE-38-1 or RE-38-2) as required by LCO 3.3.7, "Control Room Ventilation System (CRVS) Actuation Instrumentation" will automatically place the CRVS in the pressurization mode (mode 2). In the pressurization mode, either of the two filter booster fans (CCRBF-21 or CCRCF-22) will maintain the control room at a slight positive pressure relative to adjacent areas.

  B

- Toilet area exhaust fan (K-8) is tripped and the associated exhaust flow path is isolated by series redundant dampers (CCRD4 and CCRD5). This action completes the control room envelope to permit pressurization.

- Dampers (CCRA1 and CCRA2) in the flowpath that allows outside air to bypass the HEPA/adsorber filter unit close. These dampers are in series to provide required redundancy.

- Filter booster fan (CCRBF-21) starts and the associated isolation damper (F-1) opens and draws outside air through the HEPA/adsorber filter unit at a rate sufficient to pressurize the control room. The filter booster fan supplies the filtered air to the suction of the air conditioning unit fan (CCRF-21) where the filtered air is mixed with air being recirculated from the control room. If the filter booster fan (CCRBF-21) fails to start or trips, a flow switch will detect the failure and start the redundant filter booster fan (CCRBF-22) after a predetermined time delay.

- Air conditioning unit fan (CCRF-21) recirculates the mixture of filtered outside air and control room air. If the air conditioning unit fan (CCRF-21) fails to start or trips, a flow switch will detect the failure and a redundant fan (CCRCF-22) will start. The redundant fan will continue to recirculate control room air but will bypass the air conditioning unit.

<u>Incident 100% recirculation mode (mode 3) for the CRVS</u> is used for protection from smoke. In this mode, the CRVS is aligned for 100% recirculation of control room air through the air conditioning unit with no outside air makeup.

The original CRVS design was not required to meet single failure criteria but has been upgraded so that the active mechanical components needed for pressurization mode (mode 2) are redundant. To meet this requirement, the CRVS ~~system~~ is divided into two trains as follows:

BASES

LCO (continued)

This LCO governs only those portions of the CRVS needed to ensure that the design basis single active failure criterion is met for automatic protection against airborne radiation using the filtered pressurization mode of operation (mode 2).

The LCO is modified by a Note allowing the control room boundary to be opened intermittently under administrative controls. For entry and exit through doors, the administrative control of the opening is performed by the person(s) entering or exiting the area. For other openings, these controls consist of stationing a dedicated individual at the opening who is in continuous communication with the control room. This individual will have a method to rapidly close the opening when a need for control room isolation is indicated.

Technical Requirements Manual (TRM) 3.9.A, "Decay Time," (Ref. 5) prevents any movement of recently irradiated fuel by prohibiting movement of any fuel in the reactor until 100 hours after reactor shutdown.

APPLICABILITY

In MODES 1, 2, 3 and 4, CRVS must be OPERABLE to control operator exposure during and following a DBA.

During movement of recently irradiated fuel assemblies, the CRVS must be OPERABLE to cope with the release from a fuel handling accident involving handling recently irradiated fuel. The CRVS is only required to be OPERABLE during fuel handling involving ~~handling~~ recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 100 hours), due to radioactive decay.

ACTIONS

<u>A.1</u>

When one CRVS train is inoperable, action must be taken to restore OPERABLE status within 7 days. In this Condition, the remaining OPERABLE CRVS train is adequate to perform the control room protection function. However, the overall reliability is reduced because a single failure in the OPERABLE CRVS train could result in loss of CRVS function. The 7 day Completion Time is based on the low probability of a DBA occurring during this time period, and ability of the remaining train to provide the required capability.

BASES

ACTIONS (continued)

B.1

When neither CRVS train is ~~Operable~~ (which includes an inoperable control room boundary), action must be taken to restore at least one train to OPERABLE status within 72 hours. The 72 hour Completion Time is acceptable because of the low probability of a DBA occurring during this time period.

C.1 and C.2

If the inoperable CRVS train or control room boundary cannot be restored to OPERABLE status within the required Completion Time, the unit must be placed in a MODE that minimizes accident risk. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

D.1 and D.2

Reference 3 did not address exposure to control room operators resulting from fuel handling accidents when less than 100 hours of decay time have elapsed if the control room ventilation safety function is not met. Therefore, when only one CRVS train is OPERABLE during movement of recently irradiated fuel, action must be taken to immediately place the OPERABLE CRVS train in the pressurization mode. This action ensures that the remaining train is OPERABLE, that no failures preventing automatic actuation will occur, and that any active failure would be readily detected. An alternative to Required Action D.1 is to immediately suspend activities that could result in a release of radioactivity that might require isolation of the control room. This places the unit in a condition that minimizes risk. This does not preclude the movement of fuel to a safe position.

E.1

Reference 3 did not address exposure to control room operators resulting from fuel handling accidents when less than 100 hours of decay time have elapsed if the control room ventilation safety function is not met. Therefore, when neither CRVS train is OPERABLE during movement of recently irradiated fuel, action must be taken immediately to suspend activities that could result in a release of radioactivity that might enter the control room. This places the unit in a condition that minimizes accident risk. This does not preclude the movement of fuel to a safe position.

3.7 PLANT SYSTEMS

3.7.11 Spent Fuel Pit Water Level

LCO 3.7.11 The spent fuel pit water level shall be ≥ 23 ft over the top of irradiated fuel assemblies seated in the storage racks.

APPLICABILITY: During movement of irradiated fuel assemblies in the spent fuel pit.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Spent fuel pit water level not within limit.	A.1 ---------- - NOTE - ---------- LCO 3.0.3 is not applicable. ------------------------------ Suspend movement of irradiated fuel assemblies in the spent fuel pit.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.11.1	Verify the spent fuel pit water level is ≥ 23 ft above the top of the irradiated fuel assemblies seated in the storage racks.	7 days

B 3.7 PLANT SYSTEMS

B 3.7.11 Spent Fuel Pit Water Level

BASES

BACKGROUND

The minimum water level in the spent fuel pit meets the assumptions of iodine decontamination factors following a fuel handling accident. The specified water level shields and minimizes the general area dose when the storage racks are filled to their maximum capacity. The water also provides shielding during the movement of spent fuel.

A general description of the spent fuel pit including the cooling and cleanup system is given in the UFSAR, Section 9.3 (Ref. 1). The assumptions of the fuel handling accident are given in References 2 and 3.

APPLICABLE SAFETY ANALYSES

The minimum water level in the ~~fuel storage pool~~ spent fuel pit meets the assumptions of the fuel handling accident evaluated in Reference 3 when the radiological consequence analyses for Indian Point 2 were revised to demonstrate compliance with 10 CFR 50.67, Accident Source Term (Ref. 4). The radiological consequence analysis for a fuel handling accident in the fuel storage building assumes that a fuel assembly is dropped and damaged during refueling.

Activity released from the damaged assembly is released to the outside atmosphere through the fuel-handling building ventilation system to the plant vent. No credit is taken for removal of iodine by filters, nor is credit taken for isolation of release paths. The activity released from the damaged assembly is assumed to be released to the environment over a 2-hour period. These assumptions are consistent with the guidance provided in NRC Draft Guide (DG)-1081. The fuel assembly fission product inventory is based on the assumption that the subject fuel assembly has been operated at 1.7 times core average power (and thus has 1.7 times the average fuel assembly fission product inventory). The decay time used in the analysis is 100 hours. In accordance with this LCO, it is assumed that there is a minimum of 23 feet of water above the spent fuel racks. With this water depth, the decontamination factor (DF) of 500 specified by DG-1081 for elemental iodine would apply. The decontamination factor was reduced to 400 for conservatism because the fuel rod pressure may exceed the NRC ~~Draft Guide (~~DG~~)~~-1081 assumption of 1200 psig (but would be less than 1500 psig). The decontamination factor for organic iodine and noble gases was 1.0.

BASES

ACTIONS (continued)

a safe position. This action effectively precludes the occurrence of a fuel handling accident. This does not preclude movement of a fuel assembly to a safe position.

If moving irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODES 1, 2, 3, and 4, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of irradiated fuel assemblies is not sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.7.11.1

This SR verifies sufficient spent fuel pit water is available in the event of a fuel handling accident. The water level in the spent fuel pit must be checked periodically. The 7 day Frequency is appropriate because the volume in the spent fuel pit is normally stable. Water level changes are controlled by plant procedures and are acceptable based on operating experience.

During refueling operations, the level in the spent fuel pit is in equilibrium with the refueling canal, and the level in the refueling cavity is checked daily in accordance with SR 3.9.~~5~~.1.

6

REFERENCES

1. UFSAR, Section 9.3.

2. UFSAR, Section 14.2.

3. Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Amendment No. 211 to Facility Operating License No. DPR-26, July 27, 2000.

4. 10 CFR 50.67.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Reference 2 also evaluated credible abnormal occurrences in accordance with ANSI/ANS-57.2-1983. This evaluation considered the effects of the following: a) a dropped fuel assembly or an assembly placed alongside a rack; b) a misloaded fuel assembly; and, c) abnormal heat loads. Reference 2 determined that the SFP will maintain a keff of ≤ 0.95 under the worst-case accident scenario if the SFP is filled with a soluble boron concentration of ≥ 1495 ppm.

NET-173-02, "Indian Point Unit 2 Spent Fuel Pool (SFP) Boron Dilution Analysis" (Ref. 3) evaluated postulated unplanned SFP boron dilution scenarios assuming an initial SFP boron concentration within the limits of LCO 3.7.12. The evaluation considered various scenarios by which the SFP boron concentration may be diluted and the time available before the minimum boron concentration necessary to ensure subcriticality for the non-accident condition (i.e. it is not assumed an assembly is misloaded concurrent with the Spent Fuel Pit dilution event). Reference 3 determined that an unplanned or inadvertent event that could dilute the SFP boron concentration from 2000 ppm to 786 ppm is not a credible event because of the low frequency of postulated initiating events and because the event would be readily detected and mitigated by plant personnel through alarms, flooding, and operator rounds through the SFP area.

References 2 and 3 are based on conservative projections of amount of Boraflex absorber panel degradation assumed in each sub-region. These projections are valid through the end of the year 2006. These compensatory measures for boraflex degradation in the SFP were evaluated by the NRC in Reference 4.

spent fuel pit

The concentration of dissolved boron in the ~~fuel storage pool~~ satisfies Criterion 2 of 10 CFR 50.36 (c)(2)(ii).

LCO

The Spent Fuel Pit boron concentration is required to be ≥ 2000 ppm. The specified concentration of dissolved boron in the Spent Fuel Pit preserves the assumptions used in the analyses of the potential critical accident scenarios as described in Reference 2. This concentration of dissolved boron is the minimum required concentration for fuel assembly storage and movement within the Spent Fuel Pit.

APPLICABILITY

This LCO applies whenever fuel assemblies are stored in the Spent Fuel Pit.

3.8 ELECTRICAL POWER SYSTEMS

3.8.1 AC Sources - Operating

LCO 3.8.1 The following AC electrical sources shall be OPERABLE:

a. Two qualified circuits between the offsite transmission network and the onsite AC Electrical Power Distribution System; and

b. Three diesel generators (DGs) capable of supplying the onsite power distribution subsystem(s).

- NOTE -

The automatic transfer function for the 6.9 kV buses shall be OPERABLE whenever the 138 kV offsite circuit is supplying 6.9 kV bus 5 and 6 and the Unit Auxiliary Transformer is supplying 6.9 kV bus 1, 2, 3 or 4.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

- NOTE -

LCO 3.0.4.b is not applicable to ~~DGS~~ DG or the 138 kV offsite circuit.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One offsite circuit inoperable.	A.1 Perform SR 3.8.1.1 for OPERABLE offsite circuit. AND	1 hour AND Once per 8 hours thereafter

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.6	Verify the fuel oil transfer system operates to automatically transfer fuel oil from the associated storage tank to the day tank.	92 days
SR 3.8.1.7	- NOTE - This Surveillance shall not normally be performed in MODE 1 or 2. However, this Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Verify manual transfer of AC power sources from the normal offsite circuit to the alternate offsite circuit.	24 months
SR 3.8.1.8	- NOTES - 1. This Surveillance shall not normally be performed in MODE 1 or 2. However, this Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. 2. Only required to be met if 138 kV offsite circuit is supplying 6.9 kV bus 5 and 6 and the Unit Auxiliary Transformer is supplying 6.9 kV bus 1, 2, 3 or 4. Verify automatic transfer of AC power for 6.9 kV buses 2 and 3 from the unit auxiliary transformer to 6.9 kV buses 5 and 6.	24 months

BASES

BACKGROUND (continued)

In the event of a loss of the 138 kV offsite circuit, the ESF electrical loads are automatically connected to the DGs in sufficient time to provide for safe reactor shutdown and to mitigate the consequences of a Design Basis Accident (DBA) such as a loss of coolant accident (LOCA).

Certain required unit loads are returned to service in a predetermined sequence in order to prevent overloading the DG in the process. Within 1 minute after the initiating signal is received, all loads needed to recover the unit or maintain it in a safe condition are returned to service.

Ratings for DGs 21, 22 and 23 are consistent with the requirements of Regulatory Guide 1.9 (Ref. 3). Each diesel generator consists of an Alco Model 16-251-E engine coupled to a Westinghouse 900 rpm, 3-phase, 60-cycle, 480 V generator. Each diesel generator has a capability of 1750 kW (continuous), 2300 kW for 1/2 hour in any 24 hour period, and 2100 kW for 2 hours in any 24 hour period. There is a sequential limitation whereby it is unacceptable to operate DGs for two hours at 2100 kW followed by operating at 2300 kW for a half hour. Any other combination of the above ratings is acceptable. The ESF loads that are powered from the 480 V ESF buses are listed in Reference 2.

APPLICABLE SAFETY ANALYSES

The initial conditions of DBA and transient analyses in the UFSAR, Chapter 6 (Ref. 4) and Chapter 14 (Ref. 5), assume ESF systems are OPERABLE. The AC electrical power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System (RCS), and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

The OPERABILITY of the AC electrical power sources is consistent with the initial assumptions of the Accident analyses and is based upon meeting the design basis of the unit. This results in maintaining at least 2 of the 3 safeguards power trains energized from either onsite or offsite AC sources during Accident conditions in the event of:

a. An assumed loss of all offsite power or all onsite AC power and

b. A worst case single failure.

The AC sources satisfy Criterion 3 of 10 CFR 50.36.

BASES

ACTIONS (continued)

A.1

To ensure a highly reliable power source remains with one offsite circuit inoperable, it is necessary to verify the OPERABILITY of the remaining required offsite circuit on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action not met. However, if a second required circuit fails SR 3.8.1.1, the second offsite circuit is inoperable, and Condition C, for two offsite circuits inoperable, is entered.

A.2

Required Action A.2, which applies only if the 13.8 kV offsite power circuit is being used to feed 6.9 kV buses 5 ~~and~~ or 6 and the UAT is supplying 6.9 kV bus 1, 2, 3 or 4, prevents the automatic transfer of 6.9 kV buses 1, 2, 3, and 4 from the UAT to the 13.8 kV offsite power circuit after a unit trip. Transfer of buses 1, 2, 3, and 4 from the UAT to the 13.8 kV offsite power circuit could result in overloading the 13.8 kV/6.9 kV autotransformer. This requirement is not intended to preclude supplying 6.9 kV buses 1, 2, 3, and 4 using the 13.8 kV offsite circuit via the 13.8 kV/6.9 kV auto-transformers once sufficient loads have been stripped from 6.9 kV buses 1, 2, 3, and 4 to assure that the 13.8 kV/6.9 kV auto-transformer will not be overloaded. Automatic transfer of buses 1, 2, 3, and 4 can be disabled by placing 6.9 kV bus tie breaker control switches 1-5, 2-5, 3-6, and 4-6 in the "pull-out" position. These breaker control switches should be "tagged" in the pull-out position if this condition is expected to last more than one full shift.

Although the auto-transfer feature is normally disabled prior to placing the 13.8 kV offsite power circuit in service, a Completion Time of 1 hour ensures that the 13.8 kV circuit meets requirements for Operability promptly when the alternate offsite circuit is configured to support the response of ESF functions.

A.3

Required Action A.3, which only applies if the train will not be automatically powered from an offsite source, is intended to provide assurance that an event coincident with a single failure of the associated DG will not result in a complete loss of redundant required features. When one or more offsite sources are inoperable, a train may not be automatically powered from an

BASES

ACTIONS (continued)

In the event the inoperable DG is restored to OPERABLE status prior to completing either B.3.1 or B.3.2, the plant corrective action 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.

(Ref. 10)

According to Generic Letter 84-15 ~~(Ref. 7)~~, 24 hours is reasonable to confirm that the OPERABLE DGs 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 Distribution System. The 7 day Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

C.1 and C.2

Required Action C.1, which applies when two offsite circuits are inoperable, is intended to provide assurance that an event with a coincident single failure will not result in a complete loss of redundant required safety functions. The Completion Time for this failure of redundant required features is reduced to 12 hours from that allowed for one train without offsite power (Required Action A.3). The rationale for the reduction to 12 hours is that Regulatory Guide 1.93 (Ref. 6) allows a Completion Time of 24 hours for two required offsite circuits inoperable, based upon the assumption that three complete safeguards power trains are OPERABLE. When a redundant required feature is not OPERABLE, this assumption is not the case, and a shorter Completion Time of 12 hours is appropriate. These features are powered from redundant AC safety trains. This includes motor driven auxiliary feedwater pumps. Single train features, such as turbine driven auxiliary pumps, are not included as discussed in the Bases for Required Action A.3.

BASES

SURVEILLANCE REQUIREMENTS (continued)

checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are established by Regulatory Guide 1.137 (Ref. 8). This SR is for preventative maintenance. The presence of water does not necessarily represent failure of this SR, provided the accumulated water is removed during the performance of this Surveillance.

SR 3.8.1.6

This Surveillance demonstrates that each required fuel oil transfer pump operates and transfers fuel oil from its associated storage tank to its associated day tank. This is required to support continuous operation of standby power sources. This Surveillance provides assurance that the fuel oil transfer pump is OPERABLE, the fuel oil piping system is intact, the fuel delivery piping is not obstructed, and the controls and control systems for automatic fuel transfer systems are OPERABLE.

The IP2 design includes the following backup feature. If a fuel oil transfer pump fails to refill the day tank, one of the fuel oil transfer pumps associated with a different DG will receive an automatic starting signal and will fill the day tank for the affected DG via the common makeup line to all three diesel-generator fuel-oil day tanks. This backup feature is not required for DG OPERABILITY; however, the feature is tested because its existence is part of the justification for the 92 day SR Frequency. Therefore, the need for accelerated testing of the transfer function should be evaluated when this backup feature is out of service.

The Frequency for this SR is 92 days. The 92 day Frequency corresponds to the testing requirements for pumps as contained in the ASME Code, Section XI ~~(Ref. 11)~~.

SR 3.8.1.7

Transfer of each offsite power supply from the 138 kV offsite circuit to the 13.8 kV offsite circuit demonstrates the OPERABILITY of the alternate circuit distribution network to power the shutdown loads. The 24 month Frequency of the Surveillance is based on engineering judgment, taking into consideration the unit 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 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

BASES

SURVEILLANCE REQUIREMENTS (continued)

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, unit safety systems. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g. post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced.

SR 3.8.1.8

Verification that 6.9 kV buses 2 and 3 will auto transfer (dead fast transfer) from the Unit Auxiliary Transformer (the main generator) to 6.9 kV buses 5 and 6 (the offsite circuit) following a loss of voltage on 6.9 kV buses 2 and 3 is needed to confirm the Operability of a function assumed to operate to provide offsite power to safeguards power train 2A/3A following a trip of the main generator. (Note that when the main generator trips on over-frequency, the transfer is blocked by an over-frequency transfer interrupt circuit provided for bus protection of out of phase transfer.)

An actual demonstration of this feature requires the tripping the main generator while the reactor is at power with the main generator supplying 6.9 kV buses 2 and 3. Credit may be taken for planned plant trips or for unplanned events that satisfy this SR. Other than planned plant trips or unplanned events, Note 1 specifies that this SR is not normally performed in MODE 1 or 2 because performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, unit safety systems. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g. post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced.

In lieu of actually initiating a circuit transfer, this SR may be satisfied by testing that adequately shows the capability of the transfer. This transfer testing may include any sequence of sequential, overlapping, or total steps so that the entire transfer sequence is verified.

BASES

SURVEILLANCE REQUIREMENTS (continued)

load and that safety analysis assumptions regarding ESF equipment time delays are not violated. Reference 2 provides a summary of the automatic loading of ESF buses.

The Frequency of 24 months is based on engineering judgment, taking into consideration operating experience that has shown that these components usually pass the SR. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note that specifies that load timers associated with equipment that has automatic initiation capability disabled are not required to be OPERABLE. This note is needed because these time delay relays affect the Operability of both the AC sources (offsite power and DG) and the specific load that the relay starts. If a timer fails to start a required load or if a timer starts the load later than assumed in the analysis, then the required load is not OPERABLE. If a timer starts the load outside the design interval (early or late), then the DG and offsite source are not OPERABLE because overlap of equipment starts may cause an offsite source to exceed limits for voltage or current or a DG to exceed limits for voltage, current or frequency. Therefore, when an individual load sequence timer is not OPERABLE, it is conservative to disable the automatic initiation capability of that component (and declare the specific component inoperable) rather than declare the associated DG and offsite circuit inoperable because of the following: the potential for adverse impact on the DG by simultaneous start of ESF equipment is eliminated; all other loads powered from the safeguards power train are available to respond to the event; and, the load with the inoperable timer remains available for a manual start after the one minute completion of the normal starting sequence.

If a load sequence timer is inoperable and the automatic initiation capability of that component has not been disabled, Condition D applies because both the associated DG and the 138 kV offsite circuit are inoperable until automatic initiation capability of the associated component has been disabled.

SR 3.8.1.12

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.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.13

This Surveillance demonstrates that the DG starting independence has not been compromised. Also, this Surveillance demonstrates that each engine can achieve proper speed within the specified time when the DGs are started simultaneously.

The 10 year Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3).

This SR is modified by two Notes. The reason for Note 1 is to minimize wear on the DG during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is to allow SR 3.8.1.12 to satisfy the requirements of this SR if SR 3.8.1.12 is performed with more than one safeguards power train concurrently.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. UFSAR, Chapter 8.
3. Regulatory Guide 1.9, Rev. 3, July 1993.
4. UFSAR, Chapter 6.
5. UFSAR, Chapter 14.
6. Regulatory Guide 1.93, Rev. 0, December 1974.
7. 10 CFR 50, Appendix A, GDC 18.
8. Regulatory Guide 1.137.
9. IEEE Standard 387-1995, IEEE Standard Criteria for Diesel-Generator Units Applied as Standby Power Supplies for Nuclear Power Generating Stations.

10. Generic Letter 84-15, July 2, 1984.

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
	A.2.1	Suspend CORE ALTERATIONS.	Immediately
	AND		
	A.2.2	Suspend movement of recently irradiated fuel assemblies.	Immediately
	AND		
	A.2.3	Suspend operations involving positive reactivity additions that could result in loss of required SDM or boron concentration.	Immediately
	AND		
	A.2.4	Initiate action to restore required offsite power circuit to OPERABLE status.	Immediately
B. One or more required DG inoperable.	B.1	Declare affected required feature(s) with no DG available inoperable.	Immediately
	OR		
	B.2.1	Suspend CORE ALTERATIONS.	Immediately
	AND		
	B.2.2	Suspend movement of recently irradiated fuel assemblies.	Immediately
	AND		

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
	B.2.3 Suspend operations involving positive reactivity additions that could result in loss of required SDM or boron concentration.	Immediately
	AND	
	B.2.4 Initiate action to restore required DG to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.2.1	- NOTES - 1. The following SRs are required to be met but are not required to be performed: SR 3.8.1.3, SR 3.8.1.10, SR 3.8.1.11, and SR 3.8.1.12. 2. Portions of SR 3.8.1.12 regarding an actual or simulated ESF actuation signal are not required to be met. For AC sources required to be OPERABLE, the SRs of Specification 3.8.1, "AC Sources - Operating," except SR 3.8.1.7, SR 3.8.1.8, SR 3.8.1.9, and SR 3.8.1.13, are applicable.	In accordance with applicable SRs

BASES

ACTIONS (continued)

A.2.1, A.2.2, A.2.3, and A.2.4

With the offsite circuit not available to all required trains, the option would still exist to declare all required features inoperable. Since this option may involve undesired administrative efforts, the allowance for sufficiently conservative actions is made. It is, therefore, required to suspend CORE ALTERATIONS, movement of recently irradiated fuel assemblies, and operations involving positive reactivity additions that could result in loss of required SDM (Mode 5) or boron concentration (Mode 6). Suspending positive reactivity additions that could result in failure to meet the minimum SDM or boron concentration limit is required to assure continued safe operation. Introduction of coolant inventory must be from sources that have a boron concentration greater than what would be required in the RCS for minimum SDM or refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation. Introduction of temperature changes including temperature increases when operating with a positive MTC must also be evaluated to ensure they do not result in a loss of required SDM.

Suspension of these activities does not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability or the occurrence of postulated events. It is further required to immediately initiate action to restore the required AC sources and to continue this action until restoration is accomplished in order to provide the necessary AC power to the unit safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required AC electrical power sources should be completed as quickly as possible in order to minimize the time during which the unit safety systems may be without sufficient power.

Pursuant to LCO 3.0.6, the Distribution System's ACTIONS would not be entered even if all AC sources to it are inoperable, resulting in de-energization. Therefore, the Required Actions of Condition A are modified by a Note to indicate that when Condition A is entered with no AC power to any required ESF bus, the ACTIONS for LCO 3.8.10 must be immediately entered. This Note allows Condition A to provide requirements for the loss of the offsite circuit, whether or not a train is de-energized. LCO 3.8.10 would provide the appropriate restrictions for the situation involving a de-energized bus.

BASES

ACTIONS (continued)

B.1

A DG would be considered inoperable if it could not support its associated safeguards power train. One Operable DG and its associated safeguards power train may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS and fuel movement. By the allowance of the option to declare required features inoperable, with no DG available, appropriate restrictions will be implemented in accordance with the affected required features LCO's ACTIONS.

B.2.1, B.2.2, B.2.3 and B.2.4

When two DGs are required to be OPERABLE and one required DG is inoperable, the option would still exist to declare inoperable all required features supported by the inoperable DG. Since this option may involve undesired administrative efforts, the allowance for sufficiently conservative actions is made. Therefore, with one required DG inoperable, the option exists to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies, and operations involving positive reactivity additions.

With two required DGs inoperable, the minimum required diversity of AC power sources is not available to any required features. Although the option would still exist to declare all required features inoperable, the requirements imposed by the affected required features LCO's ACTIONS would be equivalent to the option provided by Required Actions B.2.1, B.2.2 and B.2.3. Therefore, with two required DGs inoperable, it is required to suspend CORE ALTERATIONS, movement of recently irradiated fuel assemblies, and operations involving positive reactivity additions.

With one required DG inoperable, when only one is required to be operable, the available options are equivalent to the situation described above for two inoperable DGs when two DGs are required. The additional restrictions on plant conditions for requiring only one DG provides ample time for operator action, in the event of a loss of offsite power, to manually restore decay heat removal capability.

With one or more required DGs inoperable, the Required Action to suspend positive reactivity additions does not preclude actions to maintain or increase reactor vessel inventory provided the required SDM is maintained. Additionally, Required Actions B.2.1, B.2.2 and B.2.3 do not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability or the occurrence of postulated events.

BASES

ACTIONS (continued)

Furthermore, even when Required Actions B.2.1, B.2.2 and B.2.3 are implemented, it is required to immediately initiate action to restore the required DG(s) and to continue this action until restoration is accomplished in order to provide the necessary AC power to the unit safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required AC electrical power sources should be completed as quickly as possible in order to minimize the time during which the unit safety systems may be without sufficient power.

SURVEILLANCE REQUIREMENTS

SR 3.8.2.1

SR 3.8.2.1 requires the SRs from LCO 3.8.1 that are necessary for ensuring the OPERABILITY of the AC sources in other than MODES 1, 2, 3, and 4. SR 3.8.1.7 is not required to be met since only one offsite circuit is required to be OPERABLE. SR 3.8.1.8 is not required because autotransfer from the Unit Auxiliary Transformer to an offsite source is not needed when the plant is not at power. SR 3.8.1.9 is not required to be met because the required OPERABLE DG(s) is not required to undergo periods of being synchronized to the offsite circuit. SR 3.8.1.13 is excepted because starting independence is not required with the DG(s) that is not required to be operable.

This SR is modified by two Notes. The reason for Note 1 is to preclude requiring the OPERABLE DG(s) from being paralleled with the offsite power network or otherwise rendered inoperable during performance of SRs, and to preclude deenergizing a required 480 V bus or disconnecting a required offsite circuit during performance of SRs. With limited AC sources available, a single event could compromise both the required circuit and the DG. It is the intent that these SRs must still be capable of being met, but actual performance is not required during periods when the DG and offsite circuit is required to be OPERABLE. Refer to the corresponding Bases for LCO 3.8.1 for a discussion of each SR. Note 2 states that portions of SR 3.8.1.12 are not required to be met. The SR demonstrates the DG response to an ECCS signal (either alone or in conjunction with a loss-of-power signal). This is consistent with the ECCS instrumentation requirements that do not require the ECCS signals when the ECCS System is not required to be OPERABLE per LCO 3.5.3, "ECCS-Shutdown."

BASES

BACKGROUND (Continued)

Each of the three DG fuel oil storage tanks is provided with a motor-driven transfer pump mounted in a manhole opening above oil level. This pump is used to transfer fuel oil from the storage tank to the 175 gallon day tank supporting each DG. A decrease in day tank level to approximately 115 gallons (65%) will start the transfer pump in the corresponding DG fuel oil storage tank and run until the day tank is at approximately 158 gallons (90%). This process ensures that the day tank always contains sufficient fuel to support approximately 53 minutes of DG operation. If pump 21 fails to refill its associated day tank, transfer pump 22 will receive an automatic starting signal as a backup to the primary pump. In a similar manner, transfer pump 22 receives an automatic starting signal on low level in the day tank for diesel 22 and is backed up by transfer pump 23. Transfer pump 23 starts on low level in the day tank for diesel generator 23 and is backed up by transfer pump 21.

If the DGs require fuel oil from the fuel oil reserve tank(s), the fuel oil will be transported by truck to the DG fuel oil storage tanks. A truck with appropriate hose connections and capable of transporting oil is available either on site or at the Buchanan Substation. Commercial oil supplies and trucking facilities are also available in the vicinity of the plant.

For proper operation of the standby DGs, it is necessary to ensure the proper quality of the fuel oil. Regulatory Guide 1.137 (Ref. 2) addresses the recommended fuel oil practices as supplemented by ANSI N195 (Ref. ~~3~~). 4 The fuel oil properties governed by these SRs are the water and sediment content, the viscosity, specific gravity (or API gravity), and impurity level. Requirements for DG fuel oil testing methodology, frequency, and acceptance criteria are maintained in the program required by Technical Specification 5.5.11, Diesel Fuel Oil Testing Program.

The DG lubrication system is designed to provide sufficient lubrication to permit proper operation of its associated DG under all loading conditions. The system is required to circulate the lube oil to the diesel engine working surfaces and to remove excess heat generated by friction during operation. Administrative controls ensure that the combination of the lube oil in the engine oil sump and maintained in onsite storage is sufficient to support 7 days of continuous operation of all three DGs. This supply is sufficient to allow operators to replenish the lube oil from offsite sources.

BASES

BACKGROUND (continued)

Each emergency diesel is automatically started by two redundant air motors. Each DG has a 53-ft^3 air storage tank and compressor system powered by a 480-V motor. The piping and the electrical services are arranged so that manual transfer between units is possible. The capability exists to cross-connect a single DG air compressor to more than one DG air receiver, via manual air tie valves. However, to ensure that the OPERABILITY of two of the three DGs is maintained in the event of a single failure, administrative controls are in-place to require an operator to be stationed within the DG Building, whenever any of the starting air tie valves are opened. Each air receiver has sufficient storage for four normal starts. However, all starting air will be consumed during a failed start attempt.

Font

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Chapter 14 (Ref. 3), assume Engineered Safety Feature (ESF) systems are OPERABLE. The DGs are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that fuel, Reactor Coolant System and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

Since diesel fuel oil and the air start subsystem support the operation of the standby AC power sources, they satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The basis for a minimum volume of diesel fuel oil of 48,000 gallons (i.e. 6334 usable gallons in each of the three DG fuel oil storage tanks and 29,000 gallons in the DG fuel oil reserve) is to provide for operation of the minimum required engineered safeguards on emergency diesel power for a period of at least 168 hours. If only two of the three DG fuel oil storage tanks are available, the total remaining fuel oil in storage is sufficient to provide for operation of two DGs with recirculation loads for a period of at least 139 hours. It is also required to meet specific standards for quality. This requirement, in conjunction with an ability to obtain replacement supplies within 7 days, supports the availability of DGs required to shut down the reactor and to maintain it in a safe condition for an anticipated operational occurrence (AOO) or a postulated DBA with loss of offsite power.

BASES

LCO (Continued)

In Modes 5 and 6, LCO requirements for DG fuel oil are relaxed in recognition that reduced DG loading required to respond to events in MODES 5 and 6 significantly reduces the amount of fuel oil required in the DG fuel oil storage tanks. Therefore, the LCO requires a total of 6334 gallons of fuel oil in the tanks associated with the DGs that are required to be operable. This fuel may be stored in one tank associated with an OPERABLE DG or proportioned between the tanks associated with OPERABLE DGs. DG day tank fuel requirements, as well as transfer capability from the storage tank to the day tank, are addressed in LCO 3.8.1, "AC Sources - Operating," and LCO 3.8.2, "AC Sources - Shutdown."

The starting air system is required to have a minimum capacity for four successive normal DG starts without recharging the air start receivers.

APPLICABILITY

The AC sources (LCO 3.8.1 and LCO 3.8.2) are required to ensure the availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an AOO or a postulated DBA. Since stored diesel fuel oil and the starting air subsystem support LCO 3.8.1 and LCO 3.8.2, stored diesel fuel oil and starting air are required to be within limits when the associated DG is required to be OPERABLE.

ACTIONS

The ACTIONS Table is modified by a Note indicating that separate Condition entry is allowed for each DG. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable DG subsystem. Complying with the Required Actions for one inoperable DG subsystem may allow for continued operation, and subsequent inoperable DG subsystem(s) are governed by separate Condition entry and application of associated Required Actions.

A.1

In this Condition, the requirements of SR 3.8.3.2.a are not met for one or more DG fuel oil storage tanks. This means that replenishment of DG fuel oil from the reserve storage tanks will be needed in less time than assumed in the UFSAR (Ref. 1). Therefore, the DG(s) associated with the DG fuel oil storage tank(s) not within limits must be declared inoperable within 2 hours because replenishment of the DG fuel oil storage tank requires that fuel be transported from the DG fuel oil reserve by truck and the volume of fuel oil remaining in the DG fuel oil storage tank may not be sufficient to allow continuous DG operation while the fuel transfer is planned and conducted under accident conditions.

BASES

ACTIONS (continued)

This Condition is preceded by a Note stating that Condition A is applicable only in MODES 1, 2, 3 and 4. This Note provides recognition that reduced DG loading required to respond to events in MODES 5 and 6 significantly reduces the amount of fuel oil required in the DG fuel oil storage tanks when in these MODES.

B.1

In this Condition, the requirements of SR 3.8.3.2.b are not met. With less than the total required minimum fuel oil in one or more DG fuel oil storage tanks, the two DGs required to be operable in MODES 5 and 6 and during movement of recently irradiated fuel may not have sufficient fuel oil to support continuous operation while a fuel transfer from the offsite DG fuel oil reserve or from another offsite source is planned and conducted under accident conditions.

This condition requires that all DGs be declared inoperable immediately because minimum fuel oil level requirements in SR 3.8.3.2.b is a condition of OPERABILITY of all DGs when in the specified MODES.

This Condition is preceded by a Note stating that Condition B is applicable only in MODES 5 and 6. This Note provides recognition that reduced DG loading required to respond to events in MODES 5 and 6 significantly reduces the amount of fuel oil required in the DG fuel oil storage tanks when in these MODES.

C.1

In this Condition, the requirements of SR 3.8.3.1 are not met and the fuel oil remaining in the DG fuel oil reserve is not sufficient to operate 2 of the 3 DGs at minimum safeguards load for 7 days. Therefore, all 3 DGs are declared inoperable within 2 hours.

This Condition is preceded by a Note stating that Condition C is applicable only in MODES 1, 2, 3 and 4 because the DG fuel oil reserve is required to be available only in these MODES. This Note provides recognition that reduced DG loading required to respond to events in MODES 5 and 6 and when moving irradiated fuel and, therefore, significantly reduces the amount of fuel oil required when in these MODES.

BASES

ACTIONS (continued)

D.1

This Condition is entered as a result of a failure to meet the acceptance criterion for total particulate concentration of the fuel oil in the DG fuel oil storage tanks and/or the DG fuel oil reserve storage tanks is not within the allowable value in Technical Specification 5.5.11, Diesel Fuel Oil Testing Program, during periodic verifications required by SR 3.8.3.3 and SR 3.8.3.4. Normally, trending of particulate levels allows sufficient time to correct high particulate levels prior to reaching the limit of acceptability. Poor sample procedures (bottom sampling), contaminated sampling equipment, and errors in laboratory analysis can produce failures that do not follow a trend. Since the presence of particulates does not mean failure of the fuel oil to burn properly in the diesel engine, and particulate concentration is unlikely to change significantly between Surveillance Frequency intervals, and proper engine performance has been recently demonstrated (within 31 days), it is prudent to allow a brief period prior to declaring the associated DG inoperable. The Completion Time to restore particulate levels to within required limits is 7 days for DG fuel oil storage tanks and 30 days for reserve storage tanks. These Completion Times allow for further evaluation, resampling and re-analysis of the DG fuel oil and recognize the time that may be required to restore parameters to within limits.

This Condition is preceded by a Note that clarifies that this Condition applies to the reserve fuel oil storage tanks only in MODES 1, 2, 3 and 4.

E.1

New fuel oil may be added to the DG fuel oil storage tanks or the reserve storage tanks before results of samples of this new fuel oil are available. If the properties of new fuel oil are determined not to be within the requirements established by Technical Specification 5.5.11, "Diesel Fuel Oil Testing Program," after the fuel oil has been added to the DG fuel oil storage tanks or the reserve storage tanks, then the oil in the affected storage tank(s) must be confirmed to be within the limits established by Technical Specification 5.5.11. A Completion Time of 30 days is permitted to confirm and/or restore the DG fuel oil storage tanks to within the limits of Technical Specification 5.5.11. A Completion Time of 60 days is permitted to confirm and/or restore the DG fuel oil reserve tanks to within the limits of Technical Specification 5.5.11.

BASES

ACTIONS (continued)

F.1

With starting air receiver pressure < 250 psig, sufficient capacity for four successive DG start attempts does not exist. However, as long as the receiver pressure is ≥ 90 psig, there is adequate capacity for at least one normal start, and the DG can be considered OPERABLE while the air receiver pressure is restored to the required limit. A period of 48 hours is considered sufficient to complete restoration to the required pressure prior to declaring the DG inoperable. This period is acceptable based on the remaining air start capacity, the fact that most DG starts are accomplished on the first attempt, and the low probability of an event during this brief period. Entry into Condition F is not required when air receiver pressure is less than required limits while the DG is operating following a successful start.

G.1

With a Required Action and associated Completion Time not met, or one or more DG's fuel oil or starting air subsystem is not within limits for reasons other than addressed by Conditions A through F, the associated DG may be incapable of performing its intended function and must be immediately declared inoperable.

SURVEILLANCE REQUIREMENTS

SR 3.8.3.1

This SR provides verification that there is an adequate inventory of fuel oil in the DG fuel oil reserve to support 2 DGs at minimum safeguards load for 7 days assuming requirements for the DG fuel oil storage tanks and day tanks are met. The 7 day duration with 2 of the 3 DGs at minimum safeguards load is sufficient to place the unit in a safe shutdown condition and to bring in replenishment fuel from a commercial source.

This SR is modified by a Note that requires this SR to be met only when in Modes 1, 2, 3 or 4. The requirements for DG fuel oil are relaxed in recognition that in MODES 5 and 6 the reduced DG loading required to respond to events significantly reduces the amount of fuel oil required in the DG fuel oil storage tanks.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The 24 hour Frequency is needed because the DG fuel oil reserve is stored in fuel oil tanks that support the operation of gas turbine peaking units. This warrants frequent verification that required offsite DG fuel oil reserve volume is being maintained. Additionally, the DG fuel oil reserve includes oil designated for the exclusive use of Indian Point 3 and the IP3 UFSAR and the IP3 Technical Specifications require verification of the DG fuel oil reserve every 24 hours.

SR 3.8.3.2

SR 3.8.3.2.a provides verification when in MODES 1, 2, 3, and 4, that there is an adequate inventory of fuel oil in the storage DG fuel oil tanks to support at least 73 hours of operation of minimum safeguards equipment when all three DG fuel oil storage tanks are available or 45 hours of operation of minimum safeguards equipment when any two of the DG fuel oil storage tanks are available (Ref. 1). The 45 hour period of DG operation is sufficient time for a fuel transfer (from the fuel oil reserve or an offsite source) to be planned and conducted under accident conditions.

SR 3.8.3.2.b provides verification when in MODES 5 and 6 that the minimum required fuel oil for operation in these MODES is available in one or more DG fuel oil storage tanks. The minimum required volume of fuel oil takes into account the reduced DG loading required to respond to events in MODES 5 and 6 is sufficient to support the two DGs required to be ~~operable~~ in MODES 5 and 6 while a fuel transfer from the offsite DG fuel oil reserve or from another offsite source is planned and conducted under accident conditions.

This minimum volume required by SR 3.8.3.2.a and SR 3.8.3.2.b is the usable volume and does not include allowances for fuel not usable due to the fuel oil transfer pump cutoff switch (approximately 438 gallons). Additionally, an allowance must be made for instrument accuracy depending on the method used to determine tank volume. These adjustments must be made for each tank for SR 3.8.3.2.b if the required volume is found in more than one DG fuel oil storage tank.

The 31 day Frequency is adequate to ensure that a sufficient supply of fuel oil is available, since low level alarms are provided and unit operators would be aware of any large uses of fuel oil during this period.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.3.3 and SR 3.8.3.4

SR 3.8.3.3 requires that fuel oil properties of new and stored fuel oil in the DG fuel oil storage tanks are tested and maintained in accordance with Technical Specification 5.5.11, " Diesel Fuel Oil Testing Program."

SR 3.8.3.4 requires that fuel oil properties of new and stored fuel oil in the reserve storage tank(s) are within limits specified in Technical Specification 5.5.11. SR 3.8.3.4 is modified by a Note that requires this SR to be met only when in Modes 1, 2, 3 or 4 because the fuel oil in the reserve storage tank(s) is required only when in those MODES.

These Surveillances verify that the properties of new and stored fuel oil meet the acceptance criteria established by Technical Specification 5.5.11, "Diesel Fuel Oil Testing Program." Sampling and testing requirements for the performance of diesel fuel oil testing in accordance with applicable ASTM Standards are specified in the administrative program developed to ensure that Technical Specification 5.5.11 is met.

As required by Technical Specification 5.5.11, new fuel oil is sampled prior to addition to the DG fuel oil storage tanks and stored fuel oil is periodically sampled from the DG fuel oil storage tanks. Requirements and acceptance criteria for fuel oil are divided into 3 parts as follows:

a) tests of the sample of new fuel and acceptance criteria that must be met prior to adding the new fuel to the DG fuel oil storage tanks;

b) tests of the sample of new fuel that may be completed after the fuel is added to the DG fuel oil storage tanks; and,

c) tests of the fuel oil stored in the DG fuel oil storage tanks.

These tests are a means of determining whether new fuel oil is of the appropriate grade and has not been contaminated with substances that would have an immediate, detrimental impact on diesel engine combustion. If results from these tests are within acceptable limits, the fuel oil may be added to the storage tanks without concern for contaminating the entire volume of fuel oil in the storage tanks. These tests are to be conducted prior to adding the new fuel to the storage tank(s), but in no case is the time between receipt of new fuel and conducting the tests to exceed 31 days. The tests, limits, and applicable ASTM Standards are performed in accordance with the administrative program developed to ensure that Technical Specification 5.5.11 is met.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The 31 day Frequency takes into account the capacity, capability, redundancy, and diversity of the AC sources and other indications available in the control room, including alarms, to alert the operator to below normal air start pressure.

SR 3.8.3.6

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel storage tanks once every 31 days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, and contaminated fuel oil, and from breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are consistent with Regulatory Guide 1.137 (Ref. 2). This SR is for preventive maintenance. Unless the volume of water is sufficient that it could impact DG OPERABILITY, presence of water does not necessarily represent failure of this SR, provided the accumulated water is removed within 7 days of performance of the Surveillance.

REFERENCES

1. UFSAR, Section 8.2.
2. Regulatory Guide 1.137.
3. UFSAR, Chapter 14.
4. ANSI N195-1976, Appendix B

BASES

BACKGROUND (continued)

The preferred and alternate sources of DC control power for the breakers and DGs are:

Transfer Switch	Associated 480 V Bus	Preferred Source	Alternate Source
EDD1	6A	PPNL #24	PPNL #22
EDD2	2A	PPNL #22	PPNL #24
EDD3	3A	PPNL #23	PPNL #21
EDD4	5A	PPNL #21	PPNL #23
EDD5	DG-21	PPNL #21	PPNL #23
EDD6	DG-22	PPNL #23	PPNL #22
EDD7	DG-23	PPNL #24	PPNL #22

The DC electrical power subsystems 21, 22, 23 and 24 also provide DC electrical power to the static inverters which supply power to the 118 VAC instrument buses. Each of the four DC electrical power subsystems supports one of the four Reactor Protection System (RPS) Instrumentation channels and one of the four Engineered Safety Features Actuation System (ESFAS) Instrumentation channels. DC electrical power subsystems 21 and 22 each support one of the two trains of RPS Instrumentation actuation logic and one of the two trains of ESFAS Instrumentation actuation logic. Electrical distribution, including DC Sources, is described in the UFSAR (Ref. 4).

During normal operation, the 125 VDC load is powered from the battery chargers with the batteries floating on the system. In case of loss of normal power to the battery charger, the DC load is automatically powered from the station batteries.

The DC power distribution system is described in more detail in Bases for LCO 3.8.9, "Distribution System - Operating," and LCO 3.8.10, "Distribution Systems - Shutdown."

S

Each 125 VDC battery is separately housed in a ventilated room apart from its charger and power panels. Each subsystem is separated electrically from the other subsystem to ensure that a single failure in one subsystem does not cause a failure in a redundant subsystem. There is no sharing between redundant subsystems, such as batteries, battery chargers, or power panels.

Each battery has adequate storage capacity to meet the duty cycle(s) discussed in the UFSAR, Chapter 8 (Ref 4). The battery is designed with additional capacity above that required by the design duty cycle to allow for temperature variations and other factors.

A.2.3

ACTIONS (continued)

Required Action A.3 limits the restoration time for the inoperable battery charger to 7 days. This action is applicable if an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage has been used (e.g., balance of plant non-Class 1E battery charger). The 7 day Completion Time reflects a reasonable time to effect restoration of the qualified battery charger to OPERABLE status.

B.1.1, B.1.2, B.2 and B.3

Condition B applies when one subsystem's battery and/or charger is inoperable and the plant is not in Condition A for an inoperable battery charger in any other DC electrical power subsystem.

Each DC electrical power subsystem supplies DC control power for the associated 480 V ESF switchgear and an associated DG and supplies a static inverter associated with one of the four 118 VAC instrument buses. However, if any of the four DC electrical power subsystems (i.e., battery and/or charger) fail to maintain the associated DC power panel above the required voltage, the IP2 design provides for the automatic transfer of both DC control power and the vital instrument bus to an alternate source of power.

When a DC electrical power subsystem is inoperable for reasons other than Condition A or if the election is made to enter Condition B for an inoperable battery charger, Required Actions B.1.1 and B.1.2, require verification by administrative means that DC control power supplied by the inoperable battery and/or charger is either being supplied by the alternate source or that the automatic transfer switch that will cause the transfer to the alternate source is OPERABLE. Additionally, Required Action B.2 requires verification that inverters associated with all other DC electrical power subsystems are OPERABLE. This ensures that requirements in LCO 3.8.7, "Inverters - Operating," are met if the inoperable battery and/or changer have caused the associated static inverter to transfer to an alternate source. This Required Action also recognizes there is increased potential that the static inverter will transfer to the alternate source during an accident or transient. The 2 hour Completion Time is based on Regulatory Guide 1.93 (Ref. 6) and reflects a reasonable time to assess unit status as a function of the inoperable DC electrical power subsystem and, if alternate sources of power for DC control power and the static inverter are not available, to initiate an orderly and safe unit shutdown. Required Action B.3 requires that an inoperable subsystem (i.e. battery and/or charger) be restored within

BASES

SURVEILLANCE REQUIREMENTS (continued)

The reason for Note 2 is that performing the Surveillance would perturb the electrical distribution system and challenge safety systems. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow portions of the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g. post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1 or 2. Risk insights or deterministic methods may be used for the assessment.

SR 3.8.4.4

This SR verifies that the alternate source of DC control power will be connected immediately if the required battery and/or charger does not maintain the associated DC power panel above the required minimum voltage needed to support DC control power. This SR also confirms that DC control power will transfer back to the preferred source when preferred source voltage is restored. Specifically, the DC control power transfer switch will function as follows:

a. Transfers from the preferred source to the alternate source when the preferred source is < 100 VDC and the alternate source > 112.5 VDC; and

b. Transfers from the alternate source to the preferred source when the preferred source is > 112.5 VDC.

OPERABILITY of this feature is needed only to justify a 24 hour Completion Time for restoration of an inoperable battery and/or charger. Therefore, this SR is modified by a NOTE that this SR is not required to be met unless needed to satisfy requirements of Required Action A.1.2 when a battery and/or charger is inoperable.

B

BASES

APPLICABLE SAFETY ANALYSES (continued)

pressure boundary, reactor coolant temperature and pressure, and the corresponding stresses result in the probabilities of occurrence being significantly reduced or eliminated, and in minimal consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCO for required systems.

The shutdown Technical Specification requirements are designed to ensure that the unit has the capability to mitigate the consequences of certain postulated accidents. Worst case Design Basis Accidents which are analyzed for operating MODES are generally viewed not to be a significant concern during shutdown MODES due to the lower energies involved. The Technical specifications therefore require a lesser complement of electrical equipment to be available during shutdown than is required during operating MODES. More recent work completed on the potential risks associated with shutdown, however, have found significant risk associated with certain shutdown evolutions. As a result, in addition to the requirements established in the Technical Specifications, the industry has adopted NUMARC 91-06, "Guidelines for Industry Actions to Assess Shutdown Management," as an industry initiative to manage shutdown tasks and associated electrical support to maintain risk at an acceptable low level. This may require the availability of additional equipment beyond that required by the shutdown Technical Specifications.

The DC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The DC electrical power subsystems, each required subsystem consisting of one battery, one battery charger per battery, and the corresponding control equipment and interconnecting cabling within the train, are required to be OPERABLE to support required trains of the distribution systems required OPERABLE by LCO 3.8.10, "Distribution Systems - Shutdown." This ensures the availability of sufficient DC electrical power sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents involving handling recently irradiated fuel). DC subsystems may be cross connected in MODES 5 and 6.

APPLICABILITY

The DC electrical power sources required to be OPERABLE in MODES 5 and 6, and during movement of recently irradiated fuel assemblies, provide assurance that:

BASES

ACTIONS (continued)

concentration greater than ~~that~~ what would be required in the RCS for minimum SDM or refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation. Introduction of temperature changes including temperature increases when operating with a positive MTC must also be evaluated to ensure they do not result in a loss of required SDM.

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required DC electrical power subsystems and to continue this action until restoration is accomplished in order to provide the necessary DC electrical power to the unit safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required DC electrical power subsystems should be completed as quickly as possible in order to minimize the time during which the unit safety systems may be without sufficient power.

SURVEILLANCE REQUIREMENTS

SR 3.8.5.1

SR 3.8.5.1 requires performance of all Surveillances required by SR 3.8.4.1 through SR 3.8.4.3. Therefore, see the corresponding Bases for LCO 3.8.4 for a discussion of each SR.

This SR is modified by a Note. The reason for the Note is to preclude requiring the OPERABLE DC sources from being discharged below their capability to provide the required power supply or otherwise rendered inoperable during the performance of SRs. It is the intent that these SRs must still be capable of being met, but actual performance is not required.

REFERENCES

1. UFSAR, Chapter 14.

2. Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Amendment No. 211 to Facility Operating License No. DPR-26, July 27, 2000.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Battery parameters satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Battery parameters must remain within acceptable limits to ensure availability of the required DC power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence or a postulated DBA. Battery parameter limits are conservatively established, allowing continued DC electrical system function even with limits not met. Additional preventative maintenance, testing, and monitoring performed in accordance with the IP2 Battery Monitoring and Maintenance Program is conducted as specified in Specification 5.5.15.

APPLICABILITY

The battery parameters are required solely for the support of the associated DC electrical power subsystems. Therefore, battery parameter limits are only required when the DC power source is required to be OPERABLE. Refer to the Applicability discussion in Bases for LCO 3.8.4 and LCO 3.8.5.

ACTIONS

A.1, A.2, and A.3

With one or more cells in a battery < 2.07 V, the battery is degraded. Within 2 hours verification of the required battery charger OPERABILITY is made by monitoring the battery terminal voltage (SR 3.8.4.1) and of the overall battery state of charge by monitoring the battery float charge current (SR 3.8.6.1). This assures that there is still sufficient battery capacity to perform the intended function. Therefore, the affected battery is not required to be considered inoperable solely as a result of one or more cells in one or more batteries < 2.07 V, and continued operation is permitted for a limited period up to 24 hours.

being

Since the Required Actions only specify "perform," a failure of SR 3.8.4.1 or SR 3.8.6.1 acceptance criteria does not result in this Required Action not met. However, if one of the SRs is failed, then the appropriate Condition(s) are entered depending on the cause of the failures. If SR 3.8.6.1 is failed then Condition F may be applicable.

BASES

being

ACTIONS (continued)

Since Required Action B.1 only specifies "perform," a failure of SR 3.8.4.1 acceptance criteria does not result in the Required Action not met. However, if SR 3.8.4.1 is failed, then LCO 3.8.4, Condtion A, may be applicable.

C.1, C.2, and C.3

With one battery with one or more cells electrolyte level above the top of the plates, but below the minimum established design limits, the battery still retains sufficient capacity to perform the intended function. Therefore, the affected battery is not required to be considered inoperable solely as a result of electrolyte level not met. Required Action C.3 requires that the minimum established design limits for electrolyte level be re-established within 31 days.

d

With electrolyte level below the top of the plates, there is a potential for dryout and plate degradation. Required Actions C.1 and C.2 address this condition and are only applicable if electrolyte level is below the top of the plates. If the level is below the top of the plates, Required Action C.1 requires that level is required to be restored to above the top of the plates within 8 hours and Require Action C.2 requires that a visual inspection verify that there is no leakage from the battery.

Note that the program required by Technical Specification 5.5.15 may establish additional requirements from IEEE Standard 450-1995 (Ref. 3) for recovery from Condition A (e.g., Annex D Reference 3 could require an equalizing charge and testing in accordance with manufacturer's recommendation following the restoration of the electrolyte level to above the top of the plates).

D.1

With one battery with pilot cell temperature less than the minimum established design limits, 12 hours is allowed to restore the temperature to within limits before the battery must be declared ~~inoperable~~. A battery temperature below the design minimum results in a battery capacity less than assumed in the battery sizing calculation. This condition is acceptable for 12 hours because the condition is limited to one DC subsystem and the battery remains functional although with reduced capacity.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.7 Inverters - Operating

BASES

BACKGROUND

The inverters are the preferred source of power for the 118 VAC instrument buses because of the stability and reliability they achieve. The function of the inverter is to provide AC electrical power to the 118 VAC instrument buses. Each inverter receives power from a different DC Power Panel. The station battery provides an uninterruptible power source for the instrumentation and controls for the Reactor Protective System (RPS) and the Engineered Safety Feature Actuation System (ESFAS). Specific details on inverters and their operating characteristics are found in the UFSAR, Chapter 8 (Ref. 1).

In addition to the normal DC power source for the inverter, each inverter has an associated step-down transformer that is used as alternate input power supply (118 VAC nominal) to the instrument buses. The alternate power supply is used to synchronize the inverter output to the auxiliary electrical system and to provide continuity of power to the vital 118 VAC loads in the unlikely event of an inverter failure. Each alternate power supply can be used to support the 118 VAC loads via the inverter internal static transfer switch or via an external manual bypass switch. Using either of these methods, the alternate input power source to each inverter is the same step-down transformer.

Power is supplied to the instrument busses from the DC source via the inverter or from the step-down transformer as follows:

Inverter	Normal Source	Alternate Power Supply
21	DCPP 21	MCC 26A
22	DCPP 22	MCC 24A
23	DCPP 23	MCC 29A
24	DCPP 24	MCC 27A

In the event of a loss of DC power to the inverter, the inverter's internal static transfer switch will automatically transfer the 118 VAC loads to the alternate power supply. Additionally, each 118 VAC instrument bus has a manual transfer switch mounted in a separate enclosure that can bypass the static transfer switch and provide backup power from the alternate power supply directly to the 118 VAC buses.

BASES

BACKGROUND (continued)

To ensure that a single failure of an emergency diesel-generator will not result in the unavailability of more than one 118 VAC system, the normal and backup supplies for three of the instrument buses 21, 22, and 24 are fed from the associated emergency diesel-generator. Instrument bus 23 is normally fed from DG 22 with a backup supply from DG 21, providing diverse sources to prevent the potential loss two instrument buses due to loss of a single DG.

of

The alternate power supply to the instrument busses will be interrupted during accident conditions involving a safety injection actuation (with or without loss of offsite power) and during a loss of offsite power. The alternate power supply will be available after the emergency diesel generator re-energizes the associated 480 V MCC. Depending on the event and the inverter, operator action may be needed to re-energize the alternate power supply. Therefore, operator action may be required to re-energize an 118 V instrument bus during an SI or a LOOP if the associated inverter is being bypassed or fails during the event.

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Chapter 14 (Ref. 2), assume Engineered Safety Feature systems are OPERABLE. The inverters are designed to provide the required capacity, capability, redundancy, and reliability to ensure the availability of necessary power to the RPS and ESFAS instrumentation and controls so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

The OPERABILITY of the inverters is consistent with the initial assumptions of the accident analyses and is based on meeting the design basis of the unit. This includes maintaining required 118 VAC instrument buses OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite AC electrical power or all onsite AC electrical power and

b. A worst case single failure.

Inverters are a part of the distribution system and, as such, satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The inverters ensure the availability of AC electrical power for the systems instrumentation required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA.

Maintaining the required inverters OPERABLE ensures that the redundancy incorporated into the design of the RPS and ESFAS instrumentation and controls is maintained. The four inverters ensure an uninterruptible supply of AC electrical power to the 118 VAC instrument buses even if the 480 V safety buses are de-energized.

Operable inverters require the associated 118 VAC instrument bus to be powered by the inverter with output voltage and frequency within tolerances, and power input to the inverter from a station battery.

APPLICABILITY

The inverters are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients and

b. Adequate core cooling is provided, and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

Inverter requirements for MODES 5 and 6 are covered in the Bases for LCO 3.8.8, "Inverters - Shutdown."

ACTIONS

With an inverter inoperable, its associated 118 VAC instrument bus will be inoperable until the bus is re-energized from its associated alternate power supply. For this reason, a Note to the Actions requires entry into the Conditions and Required Actions of LCO 3.8.9, "Distribution Systems - Operating," until the 118 VAC instrument bus is energized. The Required Actions of LCO 3.8.9 will ensure that the 118 VAC instrument bus is re-energized within 2 hours.

BASES

ACTIONS (continued)

A.1

With an inverter inoperable, its associated 118 VAC instrument bus must be powered from its associated alternate power supply. However, the alternate power supply may be supported by MCCs that are stripped and not automatically re-connected following a SI signal or a LOOP. Therefore, operator action may be required to re-energize an 118 V instrument bus during an SI or a LOOP if the associated inverter is being bypassed or fails during the event.

Required Action A.1 is necessary when the backup power supply is being used in place of any of the inverters because the associated 118 VAC instrument bus may be de-energized following an SI signal or LOOP. Therefore, a loss of safety function could exist for any function powered from the 118 VAC instrument bus if that function requires power to perform the required safety function if the redundant required feature is inoperable. To compensate for a potential loss of safety function, Required Action A.1 requires declaring required feature(s) supported by associated inverter inoperable when its required redundant feature(s) is inoperable. As specified in the associated Note, this requirement only applies to feature(s) that require power to perform the required safety function (e.g., automatic actuation of core spray, Regulatory Guide 1.97 instrumentation, etc.). The 2 hour Completion Time is consistent with LCO 3.8.9, ~~AC~~ "Distribution Systems - Operating," requirements for an inoperable 118 VAC instrument bus.

A.2

Required Action A.2 is necessary because the inverter, as an uninterruptible power source to the 118 VAC instrument bus, is the preferred source for powering instrumentation with trip setpoint devices and various control circuits. When an inverter is inoperable and its 118 VAC instrument bus is powered from the alternate power supply, there is increased potential for inadvertent actuation for ESFAS or RPS functions, especially if redundant channels are inoperable and in the tripped condition. This is because these 'de-energize to actuate functions' are relying upon interruptible AC electrical power sources (offsite and onsite). Therefore, only one inverter may be inoperable at one time and an inoperable inverter must be restored to OPERABLE within 24 hours. The 24 hour Completion Time is needed because it ensures that the 118 VAC instrument buses are powered from the uninterruptible inverter source. The 24 hour Completion Time is acceptable because Required Action A.1 ensures that an inoperable inverter does not result in a loss of any safety function.

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B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.8 Inverters - Shutdown

BASES

BACKGROUND

A description of the inverters is provided in the Bases for LCO 3.8.7, "Inverters - Operating."

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Chapter 14 (Ref. 1), assume Engineered Safety Feature systems are OPERABLE. The DC to AC inverters are designed to provide the required capacity, capability, redundancy, and reliability to ensure the availability of necessary power to the Reactor Protective System and Engineered Safety Features Actuation System instrumentation and controls so that the fuel, Reactor Coolant System, and containment design limits are not exceeded.

The OPERABILITY of the inverters is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY.

The OPERABILITY of one inverter to each 118 VAC instrument bus during MODES 5 and 6 ensures that:

a. The unit can be maintained in the shutdown or refueling condition for extended periods,

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status, and

c. Adequate power is available to mitigate events postulated during shutdown, such as a fuel handling accident involving handling recently irradiated fuel. Due to radioactive decay, the AC and DC inverters are only required to mitigate fuel handling accidents involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 100 hours (Ref. 2)).

In general, when the unit is shut down, the Technical Specifications requirements ensure that the unit has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or all onsite power is not required. The rationale for this is based on the fact that many Design Basis Accidents

BASES

APPLICABILITY

The inverters required to be OPERABLE in MODES 5 and 6 and during movement of recently irradiated fuel assemblies provide assurance that:

a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel in the core,

b. Systems needed to mitigate a fuel handling accident involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 100 hours (Ref. 2)) are available,

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available, and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

Inverter requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.7.

ACTIONS

LCO 3.0.3 is not applicable while in MODE 5 or 6. However, since irradiated fuel assembly movement can occur in MODE 1, 2, 3, or 4, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operations. Entering LCO 3.0.3, while in MODE 1, 2, 3, or 4 would require the unit to be shutdown unnecessarily.

A.1, A.2.1, A.2.2, A.2.3, and A.2.4

If one or more 118 VAC instrument buses are required by LCO 3.8.10, "Distribution Systems - Shutdown," the remaining OPERABLE inverters may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS, recently irradiated fuel movement, and operations with a potential for positive reactivity additions. By the allowance of the option to declare required features inoperable with the associated inverter(s) inoperable, appropriate restrictions will be implemented in accordance with the affected required features LCOs' Required Actions. In many instances, this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS, movement of recently irradiated fuel assemblies, and operations involving positive reactivity additions) that could result in loss of required SDM (Mode 5) or boron concentration (Mode 6). Suspending

BASES

ACTIONS

LCO 3.0.3 is not applicable while in MODE 5 or 6. However, since irradiated fuel assembly movement can occur in MODE 1, 2, 3, or 4, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operations. Entering LCO 3.0.3, while in MODE 1, 2, 3, or 4 would require the unit to be shutdown unnecessarily.

A.1, A.2.1, A.2.2, A.2.3, A.2.4, and A.2.5

Although redundant required features may require redundant trains of electrical power distribution subsystems to be OPERABLE, one OPERABLE distribution subsystem train may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS and recently irradiated fuel movement. By allowing the option to declare required features associated with an inoperable distribution subsystem inoperable, appropriate restrictions are implemented in accordance with the affected distribution subsystem LCO's Required Actions. In many instances, this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS, movement of recently irradiated fuel assemblies, and operations involving positive reactivity additions that could result in loss of required SDM (Mode 5) or boron concentration (Mode 6). Suspending positive reactivity additions that could result in failure to meet the minimum SDM or boron concentration limit is required to assure continued safe operation. Introduction of coolant inventory must be from sources that have a boron concentration greater than what would be required in the RCS for minimum SDM or refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation. Introduction of temperature changes including temperature increases when operating with a positive MTC must also be evaluated to ensure they do not result in a loss of required SDM.

Suspension of these activities does not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required AC and DC electrical power distribution subsystems and to continue this action until restoration is accomplished in order to provide the necessary power to the unit safety systems.

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.3.1	Verify each required containment penetration is in the required status.	7 days
SR 3.9.3.2 3	----------------------------- - NOTE - ----------------------------- Not required to be met for containment purge and exhaust valve(s) or pressure relief line isolation valve(s) in penetrations closed to comply with LCO 3.9.~~4~~.c.1. --- Verify each required containment purge and exhaust valve and pressure relief line isolation valve actuates to the isolation position on an actual or simulated actuation signal.	24 months

B 3.9 REFUELING OPERATIONS

B 3.9.3 Containment Penetrations

BASES

BACKGROUND

During movement of recently irradiated fuel assemblies within containment, a release of fission product radioactivity within containment will be restricted from escaping to the environment when the LCO requirements are met. In MODES 1, 2, 3, and 4, this is accomplished by maintaining containment OPERABLE as described in LCO 3.6.1, "Containment." In MODE 6, the potential for containment pressurization as a result of an accident is not likely; therefore, requirements to isolate the containment from the outside atmosphere can be less stringent. The LCO requirements are referred to as "containment closure" rather than "containment OPERABILITY." Containment closure means that all potential escape paths are closed or capable of being closed. Since there is no potential for containment pressurization, the Appendix J leakage criteria and tests are not required.

The containment serves to contain fission product radioactivity that may be released from the reactor core following an accident, such that offsite radiation exposures are maintained well within the requirements of 10 CFR 50.67, "Accident Source Term." Additionally, the containment provides radiation shielding from the fission products that may be present in the containment atmosphere following accident conditions.

The containment equipment hatch, which is part of the containment pressure boundary, provides a means for moving large equipment and components into and out of containment. During movement of recently irradiated fuel assemblies within containment, the opening must be closed using an equipment hatch closure plate that may include a personnel access door that is capable of being closed and the equipment hatch must be held in place by at least four bolts.

The containment air locks, which are also part of the containment pressure boundary, provide a means for personnel access during MODES 1, 2, 3, and 4 unit operation in accordance with LCO 3.6.2, "Containment Air Locks." Each air lock has a door at both ends. The doors are normally interlocked to prevent simultaneous opening when containment OPERABILITY is required. During periods of unit shutdown when containment closure is not required, the door interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods when frequent containment entry is necessary. During movement of recently irradiated fuel assemblies within containment, containment closure is required; therefore,

BASES

BACKGROUND (continued)

the door interlock mechanism may remain disabled, but one air lock door must always remain closed.

The requirements for containment penetration closure ensure that a release of fission product radioactivity within containment will be restricted to within regulatory limits.

A detailed description of the Containment Purge System (containment purge supply line and containment purge exhaust line) and the Containment Pressure Relief Line is provided in the Background of the Bases for Technical Specification 3.6.3, "Containment Isolation Valves."

Both the containment purge supply and exhaust isolation valves (FCV-1170, FCV-1171, FCV-1172, and FCV-1173) and the containment pressure relief line isolation valves (PCV-1190, PCV-1191 and PCV-1192) close when high radiation levels are detected by the Containment Air Particulate Monitor (R-41) or Containment Radioactive Gas Monitor (R-42). The Containment Phase A Isolation ESFAS signal (LCO 3.3.2, Function 3.a) and Containment Spray ESFAS signal (LCO 3.3.2, Function 2) also cause closure of the containment purge isolation valves and the containment pressure relief isolation valves.

The other containment penetrations that provide direct access from containment atmosphere to outside atmosphere must be isolated on at least one side. Isolation may be achieved by an OPERABLE automatic isolation valve, or by a manual isolation valve, blind flange, or equivalent. Equivalent isolation methods must be approved and may include use of a material that can provide a temporary, atmospheric pressure, ventilation barrier for the other containment penetrations during recently irradiated fuel movements (Ref. 1).

APPLICABLE SAFETY ANALYSES

At Indian Point 2, the radiological consequence analyses for the fuel handling accident demonstrate compliance with 10 CFR 50.67, "Accident Source Term." This analysis of a fuel handling accident is based on the assumption that decay time (i.e., fuel has decayed for greater than 100 hours) and water level are the primary success path for mitigating a fuel handling accident. This analysis assumed that activity from the damaged fuel assembly was released to the outside atmosphere through the containment purge system without taking any credit for either isolation or filtration of the release path (Ref. 2).

BASES

APPLICABLE SAFETY ANALYSES (continued)

Additionally, the analysis of a fuel handling accident (Ref. 2) demonstrated that 10 CFR 50.67 limits would be met even if the equipment hatch and personnel airlock remain open during the fuel handling accident inside containment. The analysis was performed to justify refueling operations with the containment personnel air locks and the equipment hatch open (Ref. 2).

However, the relaxations justified in Reference 2 do not apply when moving recently irradiated fuel (i.e., fuel assemblies that have been part of a critical reactor in the previous 100 hours). Therefore, during movement of recently irradiated fuel assemblies, LCO 3.9.3, "Containment Penetrations," establishes requirements for containment closure that minimize any release to the environment resulting from a fuel handling accident that occurs when the reactor has been subcritical for less than the 100 hours assumed in Reference 2.

Containment penetrations satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO limits the consequences of a fuel handling accident involving recently irradiated fuel in containment by limiting the potential escape paths for fission product radioactivity released within containment. The LCO requires any penetration providing direct access from the containment atmosphere to the outside atmosphere to be closed except for the OPERABLE containment purge and exhaust penetrations and pressure relief line penetration and the containment personnel air locks. For the OPERABLE containment purge and exhaust penetrations and pressure relief line penetration, this LCO ensures that these penetrations are isolable by the Containment Purge and Exhaust Isolation System. The OPERABILITY requirements for this LCO ensure that the automatic purge and exhaust valve closure times specified in the FSAR can be achieved and, therefore, meet the assumptions used in the safety analysis to ensure that releases through the valves are terminated, such that radiological doses are within the acceptance limit.

cannot be initiated

Technical Requirements Manual (TRM) 3.9.A specifies that ~~no~~ movement of fuel in the reactor ~~shall be made~~ until the reactor has been subcritical for ≥ 100 hours. Therefore, TRM 3.9.A prohibits movement of any fuel that can be classified as "recently irradiated."

BASES

LCO (continued)

The LCO is modified by a Note allowing penetration flow paths with direct access from the containment atmosphere to the outside atmosphere to be unisolated under administrative controls. Administrative controls ensure that 1) appropriate personnel are aware of the open status of the penetration flow path during CORE ALTERATIONS involving recently irradiated fuel or movement of recently irradiated fuel assemblies within containment, and 2) specified individuals are designated and readily available to isolate the flow path in the event of a fuel handling accident.

The containment personnel air lock doors may be open during movement of irradiated fuel in the containment and during CORE ALTERATIONS involving recently irradiated fuel provided that one door is capable of being closed in the event of a fuel handling accident. Should a fuel handling accident occur inside containment, one personnel air lock door will be closed following an evacuation of containment.

When moving irradiated fuel, the following guidelines should be included in the assessment of systems removed from service during movement of irradiated fuel:

- During fuel handling/core alterations, ventilation system and radiation monitor availability (as defined in NUMARC 91-06) should be assessed, with respect to filtration and monitoring of releases from the fuel. Following shutdown, radioactivity in the fuel decays away fairly rapidly. The basis of the Technical Specification OPERABILITY amendment is the reduction in doses due to such decay. The goal of maintaining ventilation system and radiation monitor availability is to reduce doses even further below that provided by the natural decay.

- A single normal or contingency method to promptly close primary or secondary containment penetrations should be developed. Such prompt methods need not completely block the penetration or be capable of resisting pressure.

The purpose of the "prompt methods" mentioned above are to enable ventilation systems to draw the release from a postulated fuel handling accident in the proper direction such that it can be treated and monitored.

APPLICABILITY

The containment penetration requirements are applicable during movement of recently irradiated fuel assemblies within containment because this is when there is a potential for the limiting fuel handling accident. In MODES 1, 2, 3, and 4, containment penetration requirements are addressed

BASES

ACTIONS (continued)

c. Each penetration providing direct access from the containment atmosphere to the outside atmosphere must be either closed by a manual or automatic isolation valve, blind flange, or equivalent, or verified to be capable of being closed by an OPERABLE Containment Purge and ~~Exhaust~~ Isolation System.

System

Pressure Relief Line

With RHR loop requirements not met, the potential exists for the coolant to boil and release radioactive gas to the containment atmosphere. Performing the actions described above ensures that all containment penetrations are either closed or can be closed so that the dose limits are not exceeded.

The Completion Time of 4 hours allows fixing of most RHR problems and is reasonable, based on the low probability of the coolant boiling in that time.

SURVEILLANCE REQUIREMENTS

SR 3.9.4.1

This Surveillance demonstrates that the RHR loop is in operation and circulating reactor coolant. The flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability and to prevent thermal and boron stratification in the core. The Frequency of 12 hours is sufficient, considering the flow, temperature, pump control, and alarm indications available to the operator in the control room for monitoring the RHR System.

REFERENCES

None.

3.9 REFUELING OPERATIONS

3.9.5 Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level

LCO 3.9.5 Two RHR loops shall be OPERABLE, and one RHR loop shall be in operation.

- NOTES -

1. All RHR pumps may be removed from operation for ≤ 15 minutes when switching from one loop to another provided:

   a. The core outlet temperature is maintained > 10 degrees F subcooled,

   b. No operations are permitted that would cause a reduction of the Reactor Coolant System boron concentration, and

   c. No draining operations to further reduce RCS water volume are permitted.

2. One required RHR loop may be inoperable for up to 2 hours for surveillance testing, provided that the other RHR loop is OPERABLE and in operation.

APPLICABILITY: MODE 6 with the water level < 23 ft above the top of reactor vessel flange.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or both RHR loops inoperable.	A.1	Initiate action to restore required RHR loops to OPERABLE status.	Immediately
	<u>OR</u>		
	A.2	Initiate action to establish ≥ 23 ft of water above the top of reactor vessel flange.	Immediately

BASES

APPLICABLE SAFETY ANALYSES (continued)

is assumed to be released to the environment over a two hour period. These assumptions consistent with the guidance provided in DG-1081. The fuel assembly fission product inventory is based on the assumption that the subject fuel assembly has been operated at 1.7 times core average power (and thus has 1.7 times the average fuel assembly fission product inventory) (Ref. 2).

This analysis assumed that activity from the damaged fuel assembly was released to the outside atmosphere through the containment purge system without taking any credit for either isolation or filtration of the release path. This is conservative because the containment purge supply line, containment purge exhaust line and the containment pressure relief line are expected to be isolated by a Containment Air Particulate Monitor (R-42) or Radioactive Gas Monitor (R-41) even though this isolation is not required to meet 10 CFR 50.67 limits (Ref. 2).

Refueling cavity water level satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

A minimum refueling cavity water level of 23 ft above the reactor vessel flange is required to ensure that the radiological consequences of a postulated fuel handling accident inside containment are within acceptable limits.

APPLICABILITY

LCO 3.9.6 is applicable when moving irradiated fuel assemblies within containment. The LCO minimizes the possibility of a fuel handling accident in containment that is beyond the assumptions of the safety analysis. If irradiated fuel assemblies are not present in containment, there can be no significant radioactivity release as a result of a postulated fuel handling accident. Requirements for fuel handling accidents in the spent fuel ~~pool~~ pit are covered by LCO 3.7.11, "Spent Fuel Pit Water Level."

ACTIONS

A.1

With a water level of < 23 ft above the top of the reactor vessel flange, all operations involving or movement of irradiated fuel assemblies within the containment shall be suspended immediately to ensure that a fuel handling accident cannot occur.

The suspension of fuel movement shall not preclude completion of movement of a component to a safe position.

4.0 DESIGN FEATURES

4.1 Site Location

Indian Point 2 is located on the East bank of the Hudson River at Indian Point, Village of Buchanan, in upper Westchester County, New York. The site is approximately 24 miles north of the New York City boundary line. The nearest city is Peekskill which is 2.5 miles northeast of Indian Point.

The minimum distance from the reactor center line to the boundary of the site exclusion area and the outer boundary of the low population zone, as defined in 10 CFR 100.3, is 520 meters and 1100 meters, respectively. For the purpose of satisfying 10 CFR Part 20, the "Restricted Area" is the same as the "Exclusion Area" shown in UFSAR, Figure 2.2-2.

4.2 Reactor Core

4.2.1 Fuel Assemblies

The reactor shall contain 193 fuel assemblies. Each assembly shall consist of a matrix of Zircalloy-4 or ZIRLO fuel rods. Fuel shall have a U-235 enrichment of ≤ 5.0 weight percent. Limited substitutions of Zircalloy-4, ZIRLO or stainless steel filler rods for fuel rods, in accordance with approved applications of fuel rod configurations, may be used. Fuel assemblies shall be limited to those fuel designs that have been analyzed with applicable NRC staff approved codes and methods and shown by tests or analyses to comply with all fuel safety design bases. A limited number of lead test assemblies that have not completed representative testing may be placed in nonlimiting core regions.

4.2.2 Control Rod Assemblies

rod

The reactor core shall contain 53 control rod assemblies. The control material shall be silver indium cadmium, clad with stainless steel, as approved by the NRC.

4.3 Fuel Storage

4.3.1 Criticality

4.3.1.1 The spent fuel storage racks are designed and shall be maintained with:

a. Fuel assemblies having a maximum U-235 enrichment of 5.0 weight percent,

4.0 DESIGN FEATURES

4.3 Fuel Storage (continued)

b. $k_{eff} < 1.0$ if fully flooded with unborated water, and

c. Each fuel assembly classified based on initial enrichment, burnup, cooling time and number of Integral Fuel Burnable Absorbers (IFBA) rods with individual fuel assembly storage location within the spent fuel storage rack restricted as required by Technical Specification 3.7.13.

4.3.1.2 The new fuel storage racks are designed and shall be maintained with:

a. Fuel assemblies having a maximum U-235 enrichment of 5.0 weight percent, and poisons, if necessary, to meet the limit for k_{eff},

b. $k_{eff} \leq 0.95$ if fully flooded with unborated water, and

c. A 20.5 inch center to center distance between fuel assemblies placed in the storage racks to meet the limit for k_{eff}.

4.3.2 Drainage

The spent fuel pit is designed and shall be maintained to prevent inadvertent draining of the pit below a nominal elevation of 88 feet, 6 inches.

4.3.3 Capacity

The spent fuel pit is designed and shall be maintained with a storage capacity limited to no more than 269 fuel assemblies in Region I and 1105 fuel assemblies in Region II.

5.0 ADMINISTRATIVE CONTROLS

5.2 Organization

5.2.1 Onsite and Offsite Organizations

Onsite and offsite organizations shall be established for unit operation and corporate management, respectively. The onsite and offsite organizations shall include the positions for activities affecting safety of the nuclear power plant.

a. Lines of authority, responsibility, and communication shall be defined and established throughout highest management levels, intermediate levels, and all operating organization positions. These relationships shall be documented and updated, as appropriate, in organization charts, functional descriptions of departmental responsibilities and relationships, and job descriptions for key personnel positions, or in equivalent forms of documentation. These requirements including the plant-specific titles of those personnel fulfilling the responsibilities of the positions delineated in these Technical Specifications shall be documented in the UFSAR,

b. The plant manager shall be responsible for overall safe operation of the plant and shall have control over those onsite activities necessary for safe operation and maintenance of the plant,

c. The corporate officer with direct responsibility for the plant shall have corporate responsibility for overall plant nuclear safety and shall take any measures needed to ensure acceptable performance of the staff in operating, maintaining, and providing technical support to the plant to ensure nuclear safety, and

d. The individuals who train the operating staff, carry out health physics, or perform quality assurance functions may report to the appropriate onsite manager; however, these individuals shall have sufficient organizational freedom to ensure their independence from operating pressures.

5.2.2 Unit Staff

The unit staff organization shall include the following:

a. A non-licensed operator shall be assigned to each reactor containing fuel and an additional non-licensed operator shall be assigned for each control room from which a reactor is operating in MODES 1, 2, 3, or 4.

5.2 Organization

5.2.2 Unit Staff (continued)

b. Shift crew composition may be less than the minimum requirement of 10 CFR 50.54(m)(2)(i) and 5.2.2.a and 5.2.2.f for a period of time not to exceed 2 hours in order to accommodate unexpected absence of on-duty shift crew members provided immediate action is taken to restore the shift crew composition to within the minimum requirements.

c. A radiation protection technician shall be on site when fuel is in the reactor. The position may be vacant for not more than 2 hours, in order to provide for unexpected absence, provided immediate action is taken to fill the required position.

d. Administrative procedures shall be developed and implemented to limit the working hours of personnel who perform safety related functions (e.g., licensed Senior Reactor Operators (SROs), licensed Reactor Operators (ROs), health physicists, auxiliary operators, and key maintenance personnel).

The controls shall include guidelines on working hours that ensure adequate shift coverage shall be maintained without routine heavy use of overtime.

Any deviation from the above guidelines shall be authorized in advance by the plant manager or the plant manager's designee, in accordance with approved administrative procedures, and with documentation of the basis for granting the deviation. Routine deviation from the working hour guidelines shall not be authorized.

Controls shall be included in the procedures to require a periodic independent review be conducted to ensure that excessive hours have not been assigned.

e. The operations manager or assistant operations manager shall hold an SRO license.

f. A Watch Engineer shall provide advisory technical support to the unit operations shift crew in the areas of thermal hydraulics, reactor engineering, and plant analysis with regard to the safe operation of the unit. This individual shall meet the qualifications specified by the Commission Policy Statement on Engineering Expertise on Shift. The Watch Engineer position must be manned only when in Modes 1, 2, 3, and 4 and during CORE ALTERATIONS.

5.0 ADMINISTRATIVE CONTROLS

5.4 Procedures

5.4.1 Written procedures shall be established, implemented, and maintained covering the following activities:

a. The applicable requirements and recommendations of Sections 5.2 and 5.3 of ANSI N18.7-1976 and Appendix A of Regulatory Guide 1.33, Revision 2 except as provided in the quality assurance program described or referenced in the Updated FSAR;

b. The emergency operating procedures required to implement the requirements of NUREG-0737 and to NUREG-0737, Supplement 1, as stated in Generic Letter 82-33;

c. Quality assurance for effluent and environmental monitoring;

d. Fire Protection Program Implementation; and

e. All programs specified in Technical Specification 5.5;

f. Personnel radiation protection consistent with the requirements of 10 CFR 20.

5.5 Programs and Manuals

5.5.2 Primary Coolant Sources Outside Containment

This program provides controls to minimize leakage from those portions of systems outside containment that could contain highly radioactive fluids during a serious transient or accident to levels as low as practicable. The systems include:

a. Residual Heat Removal System (RHR);

b. Chemical and Volume Control System (CVCS);

c. Safety Injection System (SIS);

d. Primary Sampling System (PSS) / Post Accident Sampling System (PASS) (until such time that a modification eliminates the PASS as a potential leakage path);

e. Post Accident Containment Air Sampling System (PACAS) (until such time that a modification eliminates the PASS as a potential leakage path);

f. Post Accident Containment Vent System (PACVS);

g. Gaseous Waste Disposal System (WDS); and

h. Secondary Boiler Blowdown Purification System (SBBPS) High Pressure Test.

The program shall include the following:

a. Preventive maintenance and periodic visual inspection requirements and

b. Integrated leak test requirements for each system at least once per 24 months.

The provisions of SR 3.0.2 are applicable.

5.5.3 Radioactive Effluent Controls Program

This program conforms to 10 CFR 50.36a for the control of radioactive effluents and for maintaining the doses to members of the public from radioactive effluents as low as reasonably achievable. The program shall be contained in the ODCM, shall be implemented by procedures, and shall include remedial actions to be taken whenever the program limits are exceeded. The program shall include the following elements:

5.5 Programs and Manuals

5.5.3 Radioactive Effluent Controls Program (continued)

a. Limitations on the functional capability of radioactive liquid and gaseous monitoring instrumentation including surveillance tests and setpoint determination in accordance with the methodology in the ODCM,

b. Limitations on the concentrations of radioactive material released in liquid effluents to unrestricted areas, conforming to concentrations specified in 10 CFR Part 20, Appendix B, Table II, Column 2, for radionuclides other than dissolved or entrained noble gases. For dissolved or entrained noble gases, the concentration shall be limited to 2×10^{-4} microcuries/ml. hard space

c. Monitoring, sampling, and analysis of radioactive liquid and gaseous effluents in accordance with 10 CFR 20.1302 and with the methodology and parameters in the ODCM,

d. Limitations on the annual and quarterly doses or dose commitment to a member of the public from radioactive materials in liquid effluents released from each unit to unrestricted areas, such that:

   1. The dose or dose commitment during any calendar quarter is less than or equal to 1.5 mrem to the total body and less than or equal to 5 mrem to any organ, and

   2. The dose or dose commitment during any calendar year is less than or equal to 3 mrem to the total body and to less than or equal to 10 mrem to any organ.

e. Determination of cumulative dose contributions from radioactive effluents for the current calendar quarter and current calendar year in accordance with the methodology and parameters in the ODCM at least every 31 days. Determination of projected dose contributions from radioactive effluents in accordance with the methodology in the ODCM at least every 31 days,

f. Limitations on the functional capability and use of the liquid and gaseous effluent treatment systems to ensure that appropriate portions of these systems are used to reduce releases of radioactivity when the projected doses in a period of 31 days would exceed the following:

   1. For liquid effluent treatment systems, projected dose due to liquid effluent releases from each reactor unit would exceed 0.06 mrem to the total body or 0.2 mrem to any organ, and

5.5 Programs and Manuals

5.5.6 Inservice Testing Program (continued)

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 Steam Generator (SG) Tube Surveillance Program

This program assures the continued integrity of the steam generator tubes that are a part of the primary coolant pressure boundary. Steam generator tubes shall be determined ~~operable~~ by the following inspection program and corrective measures:

a. Definitions

1. Imperfection is a deviation from the dimension, finish, or contour required by drawing or specification.

2. Deformation is a deviation from the initial circular cross-section of the tubing. Deformation includes the deviation from the initial circular cross-section known as denting.

3. Degradation means service-induced cracking, wastage, pitting, wear or corrosion (i.e., service-induced imperfections).

4. Degraded Tube is a tube that contains imperfections caused by degradation large enough to be reliably detected by eddy current inspection. This is considered to be 20% degradation.

5. % Degradation is an estimated % of the tube wall thickness affected or removed by degradation.

6. Defect is a degradation of such severity that it exceeds the plugging limit. A tube containing a defect is defective.

7. Plugging Limit is the degradation depth at or beyond which the tube must be plugged or repaired.

8. Hot-Leg Tube Examination is an examination of the hot-leg side tube length. This shall include the length from the point of entry at the hot-leg tube sheet around the U-bend to the top support of the cold leg.

5.5 Programs and Manuals

5.5.8 Secondary Water Chemistry Program

This program provides controls for monitoring secondary water chemistry to inhibit SG tube degradation. The program shall include:

a. Identification of a sampling schedule for the critical variables and control points for these variables,

b. Identification of the procedures used to measure the values of the critical variables,

c. Identification of process sampling points.

d. Procedures for the recording and management of data,

e. Procedures defining corrective actions for all off control point chemistry conditions, and

f. A procedure identifying the authority responsible for the interpretation of the data and the sequence and timing of administrative events, which is required to initiate corrective action.

5.5.9 Ventilation Filter Testing Program (VFTP)

A program shall be established to implement the following required testing of the Control Room Ventilation System (CRVS) in accordance with Regulatory Guide 1.52, Revision 2, March 1978, and ANSI N510-1975. Tests described in Technical Specifications 5.5.9.a, 5.5.9.b, 5.5.9.c and 5.5.9.d shall be performed:

1) Within 31 days after 720 hours of charcoal adsorber operation since the last test (requires performance of 5.5.9.c only); ~~and,~~

2) After 24 months of standby service; ~~and,~~

3) After each complete or partial replacement of the HEPA filter train or charcoal adsorber filter; ~~and,~~

4) After any structural maintenance on the system housing that could alter system integrity; ~~and~~, stet

5) After painting, fire, or chemical release in any ventilation zone communicating with the system while it is in operation.

5.5 Programs and Manuals

5.5.9 Ventilation Filter Testing Program (VFTP) (continued)

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Ventilation Filter Testing Program.

The Required testing shall:

a. Demonstrate 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 Position C.5.c of Regulatory Guide 1.52, Revision 2, March 1978, and ANSI N510-1975, while operating the system at ambient conditions and at a flow rate of 2000 cfm ±10%.

b. Demonstrate that an inplace test of the charcoal adsorber shows a penetration and system bypass < 0.05% when tested in accordance with Regulatory Position C.5.d of Regulatory Guide 1.52, Revision 2, March 1978, and ANSI N510-1975, while operating the system at ambient conditions and at a flow rate of 2000 cfm ±10%.

c. Demonstrate ~~for~~ that a laboratory test of a sample of the charcoal adsorber, when obtained as described in Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, shows the methyl iodide penetration less than 5.0% when tested in accordance with ASTM D3803-1989 at a temperature of 30°C (86°F) and a relative humidity of 95%, and a face velocity of 0.203 m/sec (40 ft/min).

d. Demonstrate that the pressure drop across the combined HEPA filters, the prefilters, and the charcoal adsorbers is less than 6 inches water gauge when tested in accordance with Regulatory Guide 1.52, Revision 2, and N510-1975 at the system flowrate of 2000 cfm (± 10%).

5.5.10 Explosive Gas and Storage Tank Radioactivity Monitoring Program

This program provides controls for potentially explosive gas mixtures contained in the Waste Gas Holdup System, the quantity of radioactivity contained in gas storage tanks, and the quantity of radioactivity contained in unprotected outdoor liquid storage tanks. The gaseous radioactivity quantities shall be determined following the methodology in Branch Technical Position (BTP) ETSB 11-5, "Postulated Radioactive Release due to Waste Gas System Leak or Failure". The liquid radwaste quantities shall be determined in accordance with Standard Review Plan, Section 15.7.3, "Postulated Radioactive Release due to Tank Failures".

5.5 Programs and Manuals

5.5.10 Explosive Gas and Storage Tank Radioactivity Monitoring Program (continued)

The program shall include:

a. The limits for concentrations of hydrogen and oxygen in the Waste Gas Holdup System and a surveillance program to ensure the limits are maintained. Such limits shall be appropriate to the system's design criteria (i.e., whether or not the system is designed to withstand a hydrogen explosion),

b. A surveillance program to ensure that the quantity of radioactivity contained in each gas storage tank is less than the amount that would result in a whole body exposure of $\geq$ 0.5 rem to any individual in an unrestricted area, in the event of an uncontrolled release of the tanks' contents, and

c. A surveillance program to ensure that the quantity of radioactivity contained in all outdoor liquid radwaste tanks that are not surrounded by liners, dikes, or walls, capable of holding the tanks' contents and that do not have tank overflows and surrounding area drains connected to the Liquid Radwaste Treatment System is less than the amount that would result in concentrations less than the limits of 10 CFR 20, Appendix B, Table 2, Column 2, at the nearest potable water supply and the nearest surface water supply in an unrestricted area, in the event of an uncontrolled release of the tanks' contents.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Explosive Gas and Storage Tank Radioactivity Monitoring Program surveillance frequencies.

5.5.11 Diesel Fuel Oil Testing Program

A diesel fuel oil testing program to implement required testing of both new fuel oil and stored fuel oil shall be established for the onsite DG fuel oil storage tanks and the DG reserve fuel oil storage tanks. The program shall include sampling and testing requirements, and acceptance criteria, all in accordance with applicable ASTM Standards.
The purpose of the program is to establish the following:

a. Verification of the acceptability of new fuel oil for use prior to addition to the DG fuel oil onsite storage tanks by determining that the fuel oil has:

1. Relative density within the limits of 0.83 to 0.89;

2. Kinematic viscosity within the limits of 1.8 to 5.8; and

5.5 Programs and Manuals

5.5.13 Safety Function Determination Program (SFDP) (continued)

b. A required system redundant to the system(s) in turn supported by the inoperable supported system is also inoperable, or

c. A required system redundant to the support system(s) for the supported systems (a) and (b) above is also inoperable.

The SFDP identifies where a loss of safety function exists. If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered. When a loss of safety function is caused by the inoperability of a single Technical Specification support system, the appropriate Conditions and Required Actions to enter are those of the support system.

5.5.14 Containment Leakage Rate Testing Program

a. A program shall establish the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," dated September, 1995.

b. The calculated peak containment internal pressure for the design basis loss of coolant accident, P_a, is assumed to be the containment design pressure of 47 psig.

c. The maximum allowable containment leakage rate, L_a, at P_a, and 271°F shall be 0.1% of containment air weight per day.

d. Leakage rate acceptance criteria:

1. Containment leakage rate acceptance criterion is 1.0 L_a. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are < 0.60 L_a for the Type B and C tests and ≤ 0.75 L_a for Type A tests.

2. Air lock testing acceptance criteria shall be established to ensure that limits for Type B and C testing in Technical Specification 5.5.14.d.1 are met.

5.5 Programs and Manuals

5.5.13 Safety Function Determination Program (SFDP) (continued)

The SFDP identifies where a loss of safety function exists. If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required

Actions of the LCO in which the loss of safety function exists are required to be entered. When a loss of safety function is caused by the inoperability of a single Technical Specification support system, the appropriate Conditions and Required Actions to enter are those of the support system.

5.5.14 Containment Leakage Rate Testing Program

a. A program shall establish the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," dated September, 1995, as modified by the following exception:

   The Type A testing frequency specified in NEI 94-01, paragraph 9.2.3, as at-least-once-per-10 years based on acceptable performance history is changed to allow a Type A testing frequency of at-least-once-per-15 years based on acceptable performance history. This is a one-time-only exception that applies only for the interval following the Type A test performed in June 1991.

b. The calculated peak containment internal pressure for the design basis loss of coolant accident, P_a, is assumed to be the containment design pressure of 47 psig.

c. The maximum allowable containment leakage rate, L_a, at P_a, and 271°F shall be 0.1% of containment steam air weight per day.

d. Leakage rate acceptance criteria : space
   1. Containment leakage rate acceptance criterion is 1.0 L_a. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are < 0.60 L_a for the Type B and C tests and ≤ 0.75 L_a for Type A tests.

   2. Air lock testing acceptance criteria shall be established to ensure that limits for Type B and C testing in Technical Specification 5.5.14.d.1 are met.

5.5 Programs and Manuals

5.5.14 Containment Leakage Rate Testing Program (continued)

3. Isolation Valve Seal Water System leakage rate acceptance criteria is 14,700 cc/hour.

e. The provisions of SR 3.0.3 are applicable to the Containment Leakage Rate Testing Program.

f. Nothing in these Technical Specifications shall be construed to modify the testing Frequencies required by 10 CFR 50, Appendix J.

5.5.15 Battery Monitoring and Maintenance Program

This Program provides for battery restoration and maintenance, based on the recommendations of IEEE Standard 450-1995, "IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications, " or of the battery manufacturer including the following:

a. Actions to restore battery cells with float voltage < 2.13 V, and

b. Actions to equalize the test battery cells that had been discovered with electrolyte level below the minimum established design limit.

5.6 Reporting Requirements

5.6.5 CORE OPERATING LIMITS REPORT (COLR) (continued)

8. Technical Specification 3.2.3, Axial Flux Difference (AFD);

9. Technical Specification 3.3.1, Reactor Protection System Instrumentation;

10. Technical Specification 3.4.1, RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits; and

11. Technical Specification 3.9.1, Boron Concentration.

b. The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

1. WCAP-9272-P-A, "Westinghouse Reload Safety Evaluation Methodology," July 1985;

2. WCAP-8385, "Power Distribution Control and Load Following Procedures - Topical Report", September 1974;

3. T.M. Anderson to K. Kniel (NRC) January 31, 1980 - Attachment: Operation and Safety Analysis Aspects of an Improved Load Follow Package;

4. NUREG-0800, Standard Review Plan, US Nuclear Regulatory Commission, Section 4.3, Nuclear Design, July 1981, including Branch Technical Position CPB 4.3-1,Westinghouse Constant Axial Offset Control (CAOC), Rev. 2, July 1981;

5. WCAP-10266-P-A Rev. 2, "The 1981 Version of Westinghouse Evaluation Model Using Bash Code", March 1987; and

6. WCAP-12945-P, Westinghouse "Code Qualification Document for Best Estimate LOCA Analyses", July, 1996.

7. Caldon, Inc. Engineering Report-80P, "Improving Thermal Power Accuracy and Plant Safety While Increasing Operating Power Level Using the LEFM √™ System," Revision 0, March 1997, and Caldon, Inc. Engineering Report-160P, "Supplement to Topical Report ER-80P: Basis for a Power Uprate With the LEFM √™ System," Revision 0, May 2000.

ATTACHMENT 2 TO NL-03-137

Clean Typed Pages Affected by Supplement 7

Entergy Nuclear Operations, Inc.
Indian Point Unit No. 2
Docket No. 50-247

1.0 USE AND APPLICATION

1.1 Definitions

- NOTE -

The defined terms of this section appear in capitalized type and are applicable throughout these Technical Specifications and Bases.

Term	Definition
ACTIONS	ACTIONS shall be that part of a Specification that prescribes Required Actions to be taken under designated Conditions within specified Completion Times.
ACTUATION LOGIC TEST	An ACTUATION LOGIC TEST shall be the application of various simulated or actual input combinations in conjunction with each possible interlock logic state required for OPERABILITY of a logic circuit and the verification of the required logic output. The ACTUATION LOGIC TEST, as a minimum, shall include a continuity check of output devices.
AXIAL FLUX DIFFERENCE (AFD)	AFD shall be the difference in normalized flux signals between the top and bottom halves of a two section excore neutron detector.
CHANNEL CALIBRATION	A CHANNEL CALIBRATION shall be the adjustment, as necessary, of the channel output such that it responds within the necessary range and accuracy to known values of the parameter that the channel monitors. The CHANNEL CALIBRATION shall encompass all devices in the channel required for channel OPERABILITY. Calibration of instrument channels with resistance temperature detector (RTD) or thermocouple sensors may consist of an inplace qualitative assessment of sensor behavior and normal calibration of the remaining adjustable devices in the channel. The CHANNEL CALIBRATION may be performed by means of any series of sequential, overlapping, or total channel steps.
CHANNEL CHECK	A CHANNEL CHECK shall be the qualitative assessment, by observation, of channel behavior during operation. This determination shall include, where possible, comparison of the channel indication and status to other indications or status derived from independent instrument channels measuring the same parameter.

1.1 Definitions

CHANNEL OPERATIONAL TEST (COT)

A COT shall be the injection of a simulated or actual signal into the channel as close to the sensor as practicable to verify OPERABILITY of all devices in the channel required for channel OPERABILITY. The COT shall include adjustments, as necessary, of the required alarm, interlock, and trip setpoints required for channel OPERABILITY such that the setpoints are within the necessary range and accuracy. The COT may be performed by means of any series of sequential, overlapping, or total channel steps.

CORE ALTERATION

CORE ALTERATION shall be the movement of any fuel, sources, or reactivity control components, within the reactor vessel with the vessel head removed and fuel in the vessel. Suspension of CORE ALTERATIONS shall not preclude completion of movement of a component to a safe position.

CORE OPERATING LIMITS REPORT (COLR)

The COLR is the unit specific document that provides cycle specific parameter limits for the current reload cycle. These cycle specific parameter limits shall be determined for each reload cycle in accordance with Specification 5.6.5. Plant operation within these limits is addressed in individual Specifications.

DOSE EQUIVALENT I-131

DOSE EQUIVALENT I-131 shall be that concentration of I-131 (microcuries/gram) that alone would produce the same thyroid dose as the quantity and isotopic mixture of I-131, I-132, I-133, I-134, and I-135 actually present. The thyroid dose conversion factors used for this calculation shall be those listed in Table III of TID-14844, AEC, 1962, "Calculation of Distance Factors for Power and Test Reactor Sites," or those listed in Table E-7 of Regulatory Guide 1.109, Rev. 1, NRC, 1977, or ICRP 30, Supplement to Part 1, page 192-212, Table titled, "Committed Dose Equivalent in Target Organs or Tissues per Intake of Unit Activity."

$\bar{E}$ - AVERAGE DISINTEGRATION ENERGY

$\bar{E}$ shall be the average (weighted in proportion to the concentration of each radionuclide in the reactor coolant at the time of sampling) of the sum of the average beta and gamma energies per disintegration (in MeV) for isotopes, other than iodines, with half lives > 30 minutes, making up at least 95% of the total noniodine activity in the coolant.

1.1 Definitions

OPERABLE - OPERABILITY	A system, subsystem, train, component, or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified safety function(s) and when all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication, and other auxiliary equipment that are required for the system, subsystem, train, component, or device to perform its specified safety function(s) are also capable of performing their related support function(s).
PHYSICS TESTS	PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation. These tests are: a. Described in UFSAR Chapter 13, "Tests and Operations," b. Authorized under the provisions of 10 CFR 50.59, or c. Otherwise approved by the Nuclear Regulatory Commission.
QUADRANT POWER TILT RATIO (QPTR)	QPTR shall be the ratio of the maximum upper excore detector calibrated output to the average of the upper excore detector calibrated outputs, or the ratio of the maximum lower excore detector calibrated output to the average of the lower excore detector calibrated outputs, whichever is greater.
RATED THERMAL POWER (RTP)	RTP shall be a total reactor core heat transfer rate to the reactor coolant of 3114.4 MWt.

1.4 Frequency

DESCRIPTION (continued)

1. The Surveillance is not required to be met in the MODE or other specified condition to be entered: or
2. The Surveillance is required to be met in the MODE or other specified condition to be entered, but has been performed within the specified Frequency (i.e., it is current) and is known not to be failed; or
3. The Surveillance is required to be met, but not performed, in the MODE or other specified condition to be entered, and is known not to be failed.

Examples 1.4-3, 1.4-4, 1.4-5, and 1.4-6 discuss these special situations.

EXAMPLES

The following examples illustrate the various ways that Frequencies are specified. In these examples, the Applicability of the LCO (LCO not shown) is MODES 1, 2, and 3.

BASES

LCO 3.0.3 (continued)

The time limits of LCO 3.0.3 allow 37 hours for the unit to be in MODE 5 when a shutdown is required during MODE 1 operation. If the unit is in a lower MODE of operation when a shutdown is required, the time limit for reaching the next lower MODE applies. If a lower MODE is reached in less time than allowed, however, the total allowable time to reach MODE 5, or other applicable MODE, is not reduced. For example, if MODE 3 is reached in 2 hours, then the time allowed for reaching MODE 4 is the next 11 hours, because the total time for reaching MODE 4 is not reduced from the allowable limit of 13 hours. Therefore, if remedial measures are completed that would permit a return to MODE 1, a penalty is not incurred by having to reach a lower MODE of operation in less than the total time allowed.

In MODES 1, 2, 3, and 4, LCO 3.0.3 provides actions for Conditions not covered in other Specifications. The requirements of LCO 3.0.3 do not apply in MODES 5 and 6 because the unit is already in the most restrictive Condition required by LCO 3.0.3. The requirements of LCO 3.0.3 do not apply in other specified conditions of the Applicability (unless in MODE 1, 2, 3, or 4) because the ACTIONS of individual Specifications sufficiently define the remedial measures to be taken.

Exceptions to LCO 3.0.3 are provided in instances where requiring a unit shutdown, in accordance with LCO 3.0.3, would not provide appropriate remedial measures for the associated condition of the unit. An example of this is in LCO 3.7.11, "Spent Fuel Pit Water Level." LCO 3.7.11 has an Applicability of "During movement of irradiated fuel assemblies in the spent fuel pit." Therefore, this LCO can be applicable in any or all MODES. If the LCO and the Required Actions of LCO 3.7.11 are not met while in MODE 1, 2, or 3, there is no safety benefit to be gained by placing the unit in a shutdown condition. The Required Action of LCO 3.7.11 of "Suspend movement of irradiated fuel assemblies in the spent fuel pit" is the appropriate Required Action to complete in lieu of the actions of LCO 3.0.3. These exceptions are addressed in the individual Specifications.

LCO 3.0.4

LCO 3.0.4 establishes limitations on changes in MODES or other specified conditions in the Applicability when an LCO is not met. It allows placing the unit in a MODE or other specified condition stated in that Applicability (e.g., the Applicability desired to be entered) when unit conditions are such that the requirements of the LCO would not be met, in accordance with LCO 3.0.4.a, LCO 3.0.4.b, or LCO 3.0.4.c.

BASES

ACTIONS (continued)

The required Completion Time of 7 days is adequate for preparing whatever operating restrictions or Surveillances that may be required to allow continued reactor operation.

B.1

If the core reactivity cannot be restored to within the 1% Δk/k limit, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours. If the SDM for MODE 3 is not met, then the boration required by the Required Actions for LCO 3.1.1 would occur. The allowed Completion Time is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.2.1

Core reactivity is verified by periodic comparisons of measured and predicted RCS boron concentrations. The comparison is made, considering that other core conditions are fixed or stable, including control rod position, moderator temperature, fuel temperature, fuel depletion, xenon concentration, and samarium concentration.

This Surveillance must be performed prior to entering MODE 1 following each refueling as an initial check on core conditions and design calculations at BOC. This Surveillance is performed again within the initial 60 effective full power days (EFPD) after entering MODE 1 following each refueling in order to adjust (normalize) the predicted reactivity values to the measured core reactivity. This SR is then required to be performed every 31 EFPD after the performance used for normalization. This Frequency is acceptable because of the slow rate of core changes due to fuel depletion and because of the presence of other indicators (QPTR, AFD, etc.) that provide prompt indication of an anomaly. The SR is modified by a Note. The Note indicates that the normalization of predicted core reactivity to the measured value, if performed, must take place within the first 60 EFPD after each fuel loading. This allows sufficient time for core conditions to reach steady state, but prevents operation for a large fraction of the fuel cycle without establishing a benchmark for the design calculations.

BASES

APPLICABLE SAFETY ANALYSES (continued)

MTC satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii). Even though it is not directly observed and controlled from the control room, MTC is considered an initial condition process variable because of its dependence on boron concentration.

LCO

LCO 3.1.3 requires the MTC to be within specified limits of the COLR to ensure that the core operates within the assumptions of the accident analysis. During the reload core safety evaluation, the MTC is analyzed to determine that its values remain within the bounds of the original accident analysis during operation.

Assumptions made in safety analyses require that the MTC be less positive than a given upper bound and more positive than a given lower bound. The MTC is most positive at BOC; this upper bound must not be exceeded. This maximum upper limit occurs at BOC, all rods out (ARO), hot zero power conditions. At EOC the MTC takes on its most negative value, when the lower bound becomes important. This LCO exists to ensure that both the upper and lower bounds are not exceeded.

During operation, therefore, the conditions of the LCO can only be ensured through measurement. The Surveillance checks at BOC and EOC on MTC provide confirmation that the MTC is behaving as anticipated so that the acceptance criteria are met.

The LCO establishes a maximum positive value that cannot be exceeded. The BOC positive limit and the EOC negative limit are established in the COLR to allow specifying limits for each particular cycle. This permits the unit to take advantage of improved fuel management and changes in unit operating schedule.

APPLICABILITY

Technical Specifications place both LCO and SR values on MTC, based on the safety analysis assumptions described above.

In MODE 1, the limits on MTC must be maintained to ensure that any accident initiated from THERMAL POWER operation will not violate the design assumptions of the accident analysis. In MODE 2 with the reactor critical, the upper limit must also be maintained to ensure that startup and subcritical accidents (such as the uncontrolled control rod assembly or group withdrawal) will not violate the assumptions of the accident analysis.

3.1 REACTIVITY CONTROL SYSTEMS

3.1.4 Rod Group Alignment Limits

LCO 3.1.4 All shutdown and control rods shall be OPERABLE.

AND

Individual indicated rod positions shall be within the following limits:

a. When THERMAL POWER is > 85% RTP, the difference between each individual indicated rod position and its group step counter demand position shall be within the limits specified in Table 3.1.4-1 for the group step counter demand position; and

b. When THERMAL POWER is ≤ 85% RTP, the difference between each individual indicated rod position and its group step counter demand position shall be ≤ 24 steps.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more rod(s) inoperable.	A.1.1 Verify SDM to be within the limits specified in the COLR.	1 hour
	OR	
	A.1.2 Initiate boration to restore SDM to within limit.	1 hour
	AND	
	A.2 Be in MODE 3.	6 hours
B. One rod not within alignment limits.	B.1 Restore rod to within alignment limits.	1 hour
	OR	

BASES

APPLICABLE SAFETY ANALYSES

Control rod misalignment accidents are analyzed in the safety analysis (References 4 and 5). The acceptance criteria for addressing control rod inoperability or misalignment are that:

a. There be no violations of:

   1. Specified acceptable fuel design limits or

   2. Reactor Coolant System (RCS) pressure boundary integrity and

b. The core remains subcritical after accident transients.

Two types of misalignment are distinguished. During movement of a control rod group, one rod may stop moving, while the other rods in the group continue. This condition may cause excessive power peaking. The second type of misalignment occurs if one rod fails to insert upon a reactor trip and remains stuck fully withdrawn. This condition requires an evaluation to determine that sufficient reactivity worth is held in the control rods to meet the SDM requirement, with the maximum worth rod stuck fully withdrawn.

Two types of analysis are performed in regard to static rod misalignment (Ref. 5). With control banks at their insertion limits, one type of analysis considers the case when any one rod is completely inserted into the core. The second type of analysis considers the case of a completely withdrawn single rod from a bank inserted to its insertion limit. Satisfying limits on departure from nucleate boiling ratio in both of these cases bounds the situation when a rod is misaligned.

When reactor power is > 85% RTP, an indicated misalignment of ± 12 steps (± 7.5 inches) between individual rod positions and the group step counter demand position will not cause the power peaking factor limits to be exceeded. This limit assumes a maximum IRPI instrument error of ± 12 steps (± 7.5 inches) allowing for an actual misalignment of ± 24 steps (± 15 inches). However, when the group step counter demand position is > 209 steps, it is acceptable for the IRPI to indicate misalignment greater than + 12 steps (i.e., may be up to + 16 steps) as specified in Table 3.1.4-1 without accounting for peaking factor margin. This is acceptable because the top of active fuel (TAF) is at 221 steps. With group step counter demand position > 209 steps and IRPI deviation > + 12 steps, the IRPI determined rod position is above the top of active fuel where it will not result in increased peaking factors for increased misalignments. Similarly, allowable negative deviation limits may increase by 1 step for every step of group step counter demand position over the top of active fuel as specified in Table 3.1.4-1. These rod misalignment limits were justified in Reference 5 and approved in Reference 6.

BASES

APPLICABLE SAFETY ANALYSES (continued)

When reactor power is ≤ 85% RTP, an indicated misalignment of ± 24 steps (± 15 inches) between individual rod (i.e., IRPI) positions and the group step counter demand position will not cause the power peaking factor limits to be exceeded. This limit assumes a maximum instrument error of ± 12 steps (± 7.5 inches) allowing for an actual misalignment of ± 36 steps (± 22.5 inches). These rod misalignment limits were justified in Reference 5 and approved in Reference 6.

As explained in Reference 5, the rod alignment limit analyses were performed using two distinct models of the IP2 core. These models addressed large variations in cycle length, number of feed assemblies, fuel enrichments and burnable poisons and are expected to bound any current or future fuel management strategies. Therefore, the results of the rod misalignment analyses are considered to be cycle independent.

Another type of misalignment occurs if one RCCA fails to insert upon a reactor trip and remains stuck fully withdrawn. This condition is assumed in the evaluation to determine that the required SDM is met with the maximum worth RCCA also fully withdrawn (Ref. 5).

The Required Actions in this LCO ensure that either deviations from the alignment limits will be corrected or that THERMAL POWER will be adjusted so that excessive local linear heat rates (LHRs) will not occur, and that the requirements on SDM and ejected rod worth are preserved.

Continued operation of the reactor with a misaligned control rod is allowed if the heat flux hot channel factor ($F_Q(Z)$) and the nuclear enthalpy hot channel factor ($F^N_{\Delta H}$) are verified to be within their limits in the COLR and the safety analysis is verified to remain valid. When a control rod is misaligned, the assumptions that are used to determine the rod insertion limits, AFD limits, and quadrant power tilt limits are not preserved. Therefore, the limits may not preserve the design peaking factors, and $F_Q(Z)$ and $F^N_{\Delta H}$ must be verified directly by incore mapping. Bases Section 3.2 (Power Distribution Limits) contains more complete discussions of the relation of $F_Q(Z)$ and $F^N_{\Delta H}$ to the operating limits.

Shutdown and control rod OPERABILITY and alignment are directly related to power distributions and SDM, which are initial conditions assumed in safety analyses. Therefore they satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES

ACTIONS (continued)

An alternative to realigning a single misaligned RCCA to the group average position is to align the remainder of the group to the position of the misaligned RCCA. However, this must be done without violating the bank sequence, overlap, and insertion limits specified in LCO 3.1.5, "Shutdown Bank Insertion Limits," and LCO 3.1.6, "Control Bank Insertion Limits." The Completion Time of 1 hour gives the operator sufficient time to adjust the rod positions in an orderly manner.

B.2.1.1 and B.2.1.2

With a misaligned rod, SDM must be verified to be within limit or boration must be initiated to restore SDM to within limit.

Power operation may continue with one RCCA trippable but misaligned, provided that SDM is verified within 1 hour. The Completion Time of 1 hour represents the time necessary for determining the actual unit SDM and, if necessary, aligning and starting the necessary systems and components to initiate boration.

B.2.2, B.2.3, B.2.4, B.2.5, and B.2.6

For continued operation with a misaligned rod, RTP must be reduced, SDM must periodically be verified within limits, hot channel factors ($F_Q(Z)$ and $F^N_{\Delta H}$) must be verified within limits, and the safety analyses must be re-evaluated to confirm continued operation is permissible.

Reduction of power to 75% RTP ensures that local LHR increases due to a misaligned RCCA will not cause the core design criteria to be exceeded. The Completion Time of 2 hours gives the operator sufficient time to accomplish an orderly power reduction without challenging the Reactor Protection System.

When a rod is known to be misaligned, there is a potential to impact the SDM. Since the core conditions can change with time, periodic verification of SDM is required. A Frequency of 12 hours is sufficient to ensure this requirement continues to be met.

Verifying that $F_Q(Z)$, as approximated by $F^C_Q(Z)$ and $F^W_Q(Z)$, and $F^N_{\Delta H}$ are within the required limits ensures that current operation at 75% RTP with a rod misaligned is not resulting in power distributions that may invalidate safety analysis assumptions at full power. The Completion Time of 72 hours allows sufficient time to obtain flux maps of the core power distribution using the incore flux mapping system and to calculate $F_Q(Z)$ and $F^N_{\Delta H}$.

BASES

ACTIONS (continued)

Once current conditions have been verified acceptable, time is available to perform evaluations of accident analysis to determine that core limits will not be exceeded during a Design Basis Event for the duration of operation under these conditions. The accident analyses presented in Reference 5 that may be adversely affected will be evaluated to ensure that the analysis results remain valid for the duration of continued operation under these conditions. A Completion Time of 5 days is sufficient time to obtain the required input data and to perform the analysis.

C.1

When Required Actions cannot be completed within their Completion Time, the unit must be brought to a MODE or Condition in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours, which obviates concerns about the development of undesirable xenon or power distributions. The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner and without challenging the plant systems.

D.1.1 and D.1.2

More than one control rod becoming misaligned from its group average position is not expected, and has the potential to reduce SDM. Therefore, SDM must be evaluated. One hour allows the operator adequate time to determine SDM. Restoration of the required SDM, if necessary, requires increasing the RCS boron concentration to provide negative reactivity, as described in the Bases for LCO 3.1.1. The required Completion Time of 1 hour for initiating boration is reasonable, based on the time required for potential xenon redistribution, the low probability of an accident occurring, and the steps required to complete the action. This allows the operator sufficient time to align the required valves and start the boric acid pumps. Boration will continue until the required SDM is restored.

A power reduction to ≤ 85% RTP will result in the LCO being met if IRPIs associated with all groups indicate within ± 24 steps (± 15 inches) of the group step counter demand position. If LCO 3.1.4.b is met when ≤ 85% RTP, realigning RCCAs to within the limits of LCO 3.1.4.a is required only as a condition for increasing power to > 85% RTP.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The shutdown bank insertion limits preserve an initial condition assumed in the safety analyses and, as such, satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The shutdown banks must be within their insertion limits any time the reactor is critical or approaching criticality. This ensures that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM following a reactor trip.

The shutdown bank insertion limits are defined in the COLR.

APPLICABILITY

The shutdown banks must be within their insertion limits, with the reactor in MODES 1 and 2. This ensures that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM following a reactor trip. The shutdown banks do not have to be within their insertion limits in MODE 3, unless an approach to criticality is being made. In MODE 3, 4, 5, or 6, the shutdown banks are fully inserted in the core and contribute to the SDM. Refer to LCO 3.1.1 for SDM requirements in MODES 3, 4, and 5. LCO 3.9.1, "Boron Concentration," ensures adequate SDM in MODE 6.

The Applicability requirements have been modified by a Note indicating the LCO requirement is suspended during SR 3.1.4.2. This SR verifies the freedom of the rods to move, and requires the shutdown bank to move below the LCO limits, which would normally violate the LCO.

ACTIONS

A.1.1, A.1.2 and A.2

When one or more shutdown banks is not within insertion limits, 2 hours is allowed to restore the shutdown banks to within the insertion limits. This is necessary because the available SDM may be significantly reduced, with one or more of the shutdown banks not within their insertion limits. Also, verification of SDM or initiation of boration within 1 hour is required, since the SDM in MODES 1 and 2 is ensured by adhering to the control and shutdown bank insertion limits (see LCO 3.1.1). If shutdown banks are not within their insertion limits, then SDM will be verified by performing a reactivity balance calculation, considering the effects listed in the Bases for SR 3.1.1.1.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.6 Control Bank Insertion Limits

BASES

BACKGROUND

The insertion limits of the shutdown and control rods are initial assumptions in all safety analyses that assume rod insertion upon reactor trip. The insertion limits directly affect core power and fuel burnup distributions and assumptions of available SDM, and initial reactivity insertion rate.

The applicable criteria for these reactivity and power distribution design requirements are 10 CFR 50, Appendix A, GDC 10, "Reactor Design," GDC 26, "Reactivity Control System Redundancy and Protection," GDC 28, "Reactivity Limits" (Ref. 1), and 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors" (Ref. 2). Limits on control rod insertion have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

The rod cluster control assemblies (RCCAs) are divided among control banks and shutdown banks. Each bank may be further subdivided into two groups to provide for precise reactivity control. A group consists of two or more RCCAs that are electrically paralleled to step simultaneously. A bank of RCCAs consists of two groups that are moved in a staggered fashion, but always within one step of each other. IP2 has four control banks and four shutdown banks. See LCO 3.1.4, "Rod Group Alignment Limits," for control and shutdown rod OPERABILITY and alignment requirements, and LCO 3.1.7, "Rod Position Indication," for position indication requirements.

The control bank insertion limits are specified in the COLR. The control banks are required to be at or above the insertion limit lines. The COLR also indicates how the control banks are moved in an overlap pattern. Overlap is the distance traveled together by two control banks. The predetermined position of control bank C, at which control bank D will begin to move with bank C on a withdrawal, will be at 118 steps for a fully withdrawn position of 231 steps. The fully withdrawn position is defined in the COLR.

The control banks are used for precise reactivity control of the reactor. The positions of the control banks are normally controlled automatically by the Rod Control System, but can also be manually controlled. They are capable of adding reactivity very quickly (compared to borating or diluting).

BASES

BACKGROUND (continued)

The power density at any point in the core must be limited, so that the fuel design criteria are maintained. Together, LCO 3.1.4, LCO 3.1.5, "Shutdown Bank Insertion Limits," LCO 3.1.6, LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," provide limits on control component operation and on monitored process variables, which ensure that the core operates within the fuel design criteria.

The shutdown and control bank insertion and alignment limits, AFD, and QPTR are process variables that together characterize and control the three dimensional power distribution of the reactor core. Additionally, the control bank insertion limits control the reactivity that could be added in the event of a rod ejection accident, and the shutdown and control bank insertion limits ensure the required SDM is maintained.

Operation within the subject LCO limits will prevent fuel cladding failures that would breach the primary fission product barrier and release fission products to the reactor coolant in the event of a loss of coolant accident (LOCA), loss of flow, ejected rod, or other accident requiring termination by a Reactor Protection System (RPS) trip function.

APPLICABLE SAFETY ANALYSES

The shutdown and control bank insertion limits, AFD, and QPTR LCOs are required to prevent power distributions that could result in fuel cladding failures in the event of a LOCA, loss of flow, ejected rod, or other accidents requiring termination by an RPS trip function.

The acceptance criteria for addressing shutdown and control bank insertion limits and inoperability or misalignment are that:

a. There be no violations of:

    1. Specified acceptable fuel design limits or

    2. Reactor Coolant System pressure boundary integrity and

b. The core remains subcritical after accident transients.

As such, the shutdown and control bank insertion limits affect safety analysis involving core reactivity and power distributions (Ref. 3).

BASES

APPLICABLE SAFETY ANALYSES (continued)

Reference 6 allows special test exceptions (STEs) to be included as part of the LCO that they affect. It was decided, however, to retain this STE as a separate LCO because it was less cumbersome and provided additional clarity.

LCO

This LCO allows the reactor parameters of MTC and minimum temperature for criticality to be outside their specified limits. In addition, it allows selected control and shutdown rods to be positioned outside of their specified alignment and insertion limits. Operation beyond specified limits is permitted for the purpose of performing PHYSICS TESTS and poses no threat to fuel integrity, provided the SRs are met.

The requirements of LCO 3.1.3, LCO 3.1.4, LCO 3.1.5, LCO 3.1.6, and LCO 3.4.2 may be suspended during the performance of PHYSICS TESTS provided:

a. RCS lowest loop average temperature is $\geq$ 541°F,

b. SDM is within the limits provided in the COLR, and

c. THERMAL POWER is < 5% RTP.

APPLICABILITY

This LCO is applicable when performing low power PHYSICS TESTS. The Applicability is stated as "During PHYSICS TESTS initiated in MODE 2" to ensure that the 5% RPT maximum power level is not exceeded. Should the THERMAL POWER EXCEED 5% RPT, and consequently the unit enters MODE 1, this Applicability statement prevents exiting this Specification and its Required Actions.

ACTIONS

A.1 and A.2

If the SDM requirement is not met, boration must be initiated promptly. A Completion Time of 15 minutes is adequate for an operator to correctly align and start the required systems and components. The operator should begin boration with the best source available for the plant conditions. Boration will be continued until SDM is within limit.

Suspension of PHYSICS TESTS exceptions requires restoration of each of the applicable LCOs to within specification.

BASES

ACTIONS (continued)

B.1

If Required Actions A.1 through A.4 are not met within their associated Completion Times, the plant must be placed in a MODE or Condition in which the LCO requirements are not applicable. This is done by placing the plant in at least MODE 2 within 6 hours.

This allowed Completion Time is reasonable based on operating experience regarding the amount of time it takes to reach MODE 2 from full power operation in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.1.1 is modified by a Note. The Note applies during the first power ascension after a refueling. It states that THERMAL POWER may be increased until an equilibrium power level has been achieved at which a power distribution map can be obtained. This allowance is modified by a Frequency condition that requires verification that $F_Q(Z)$ is within specified limits after a power rise of more than 10% RTP over the THERMAL POWER at which it was last verified to be within specified limits. Because $F_Q(Z)$ could not have previously been measured in this reload core, there is a second Frequency condition, applicable only for reload cores, that requires determination of these parameters before exceeding 75% RTP. This ensures that some determination of $F_Q(Z)$ is made at a lower power level at which adequate margin is available before going to 100% RTP. Also, this Frequency condition, together with the Frequency condition requiring verification of $F_Q(Z)$ following a power increase of more than 10%, ensures performance as soon as RTP (or any other level for extended operation) is achieved. In the absence of these Frequency conditions, it is possible to increase power to RTP and operate for 31 days without verification of $F_Q(Z)$. The Frequency condition is not intended to require verification of $F_Q(Z)$ after every 10% increase in power level above the last verification. It only requires verification after a power level is achieved for extended operation that is 10% higher than that power at which $F_Q(Z)$ was last measured.

SR 3.2.1.1

Verification that $F_Q(Z)$ is within its specified limits involves increasing $F_Q^M(Z)$ to allow for manufacturing tolerance and measurement uncertainties in order to obtain $F_Q(Z)$. Specifically, $F_Q^M(Z)$ is the measured value of $F_Q(Z)$ obtained from incore flux map results and $F_Q(Z) = F_Q^M(Z)\ 1.0815$. $F_Q(Z)$ is then compared to its specified limits.

BASES

APPLICABLE SAFETY ANALYSES

Limits on $F^N_{\Delta H}$ preclude core power distributions that exceed the following fuel design limits:

a. There must be at least 95% probability at the 95% confidence level (the 95/95 DNB criterion) that the hottest fuel rod in the core does not experience a DNB condition,

b. During a large break loss of coolant accident (LOCA), peak cladding temperature (PCT) must not exceed 2200°F,

c. During an ejected rod accident, the energy deposition to the fuel must not exceed 200 cal/gm (Ref. 1), and

d. Fuel design limits required by GDC 26 (Ref. 2) for the condition when control rods must be capable of shutting down the reactor with a minimum required SDM with the highest worth control rod stuck fully withdrawn.

For transients that may be DNB limited, the Reactor Coolant System flow and $F^N_{\Delta H}$ are the core parameters of most importance. The limits on $F^N_{\Delta H}$ ensure that the DNB design basis is met for normal operation, operational transients, and any transients arising from events of moderate frequency. The DNB design basis is met by limiting the minimum DNBR to the 95/95 DNB criterion of 1.17 using the WRB-1 CHF correlation for 15 X 15 fuel. This value provides a high degree of assurance that the hottest fuel rod in the core does not experience a DNB.

The allowable $F^N_{\Delta H}$ limit increases with decreasing power level. This functionality in $F^N_{\Delta H}$ is included in the analyses that provide the Reactor Core Safety Limits (SLs) of SL 2.1.1. Therefore, any DNB events in which the calculation of the core limits is modeled implicitly use this variable value of $F^N_{\Delta H}$ in the analyses. Likewise, all transients that may be DNB limited are assumed to begin with an initial $F^N_{\Delta H}$ as a function of power level defined by the COLR limit equation.

The LOCA safety analysis indirectly models $F^N_{\Delta H}$ as an input parameter. The Nuclear Heat Flux Hot Channel Factor ($F_Q(Z)$) and the axial peaking factors are inserted directly into the LOCA safety analyses that verify the acceptability of the resulting peak cladding temperature (Ref. 3).

BASES

APPLICABLE SAFETY ANALYSES (continued)

The fuel is protected in part by the following Technical Specifications, which ensure that the initial conditions assumed in the safety and accident analyses remain valid: LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," LCO 3.1.6, "Control Bank Insertion Limits," LCO 3.2.2, "Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$)," and LCO 3.2.1, "Heat Flux Hot Channel Factor ($F_Q(Z)$)."

$F^N_{\Delta H}$ and $F_Q(Z)$ are measured periodically using the movable incore detector system. Measurements are generally taken with the core at, or near, steady state conditions. Core monitoring and control under transient conditions (Condition 1 events) are accomplished by operating the core within the limits of the LCOs on AFD, QPTR, and Bank Insertion Limits.

$F^N_{\Delta H}$ satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

$F^N_{\Delta H}$ shall be maintained within the limits of the relationship provided in the COLR.

The $F^N_{\Delta H}$ limit identifies the coolant flow channel with the maximum enthalpy rise. This channel has the least heat removal capability and thus the highest probability for a DNB.

The limiting value of $F^N_{\Delta H}$, described by the equation contained in the COLR, is the design radial peaking factor used in the unit safety analyses.

A power multiplication factor in this equation includes an additional margin for higher radial peaking from reduced thermal feedback and greater control rod insertion at low power levels. The limiting value of $F^N_{\Delta H}$ is allowed to increase 0.3% for every 1% RTP reduction in THERMAL POWER.

APPLICABILITY

The $F^N_{\Delta H}$ limits must be maintained in MODE 1 to preclude core power distributions from exceeding the fuel design limits for DNBR and PCT. Applicability in other modes is not required because there is either insufficient stored energy in the fuel or insufficient energy being transferred to the coolant to require a limit on the distribution of core power. Specifically, the design bases events that are sensitive to $F^N_{\Delta H}$ in other modes (MODES 2 through 5) have significant margin to DNB, and therefore, there is no need to restrict $F^N_{\Delta H}$ in these modes.

BASES

ACTIONS

A.1.1

With $F^N_{\Delta H}$ exceeding its limit, the unit is allowed 4 hours to restore $F^N_{\Delta H}$ to within its limits. This restoration may, for example, involve realigning any misaligned rods or reducing power enough to bring $F^N_{\Delta H}$ within its power dependent limit. When the $F^N_{\Delta H}$ limit is exceeded, the DNBR limit is not likely violated in steady state operation, because events that could significantly perturb the $F^N_{\Delta H}$ value (e.g., static control rod misalignment) are considered in the safety analyses. However, the DNBR limit may be violated if a DNB limiting event occurs. Thus, the allowed Completion Time of 4 hours provides an acceptable time to restore $F^N_{\Delta H}$ to within its limits without allowing the plant to remain in an unacceptable condition for an extended period of time.

Condition A is modified by a Note that requires that Required Actions A.2 and A.3 must be completed whenever Condition A is entered. Thus, if power is not reduced because this Required Action is completed within the 4 hour time period, Required Action A.2 nevertheless requires another measurement and calculation of $F^N_{\Delta H}$ within 24 hours in accordance with SR 3.2.2.1.

However, if power is reduced below 50% RTP, Required Action A.3 requires that another determination of $F^N_{\Delta H}$ must be done prior to exceeding 50% RTP, prior to exceeding 75% RTP, and within 24 hours after reaching or exceeding 95% RTP. A single performance of SR 3.2.2.1 may be used to satisfy requirements of both Required Action A.2 and A.3, if it is completed within 24 hours of entering Condition A.

A.1.2.1 and A.1.2.2

If the value of $F^N_{\Delta H}$ is not restored to within its specified limit either by adjusting a misaligned rod or by reducing THERMAL POWER, the alternative option is to reduce THERMAL POWER to < 50% RTP in accordance with Required Action A.1.2.1 and reduce the Power Range Neutron Flux - High to ≤ 55% RTP in accordance with Required Action A.1.2.2. Reducing RTP to < 50% RTP increases the DNB margin and does not likely cause the DNBR limit to be violated in steady state operation. The reduction in trip setpoints ensures that continuing operation remains at an acceptable low power level with adequate DNBR margin. The allowed Completion Time of 4 hours for Required Action A.1.2.1 is consistent with those allowed for in Required Action A.1.1 and provides an acceptable time to reach the required power level from full power operation without allowing

BASES

ACTIONS (continued)

the plant to remain in an unacceptable condition for an extended period of time. The Completion Times of 4 hours for Required Actions A.1.1 and A.1.2.1 are not additive.

The allowed Completion Time of 72 hours to reset the trip setpoints per Required Action A.1.2.2 recognizes that, once power is reduced, the safety analysis assumptions are satisfied and there is no urgent need to reduce the trip setpoints. This is a sensitive operation that may inadvertently trip the Reactor Protection System.

A.2

Once the power level has been reduced per Required Action A.1.2.1, an incore flux map (SR 3.2.2.1) must be obtained and the measured value of $F^N_{\Delta H}$ verified not to exceed the allowed limit at the lower power level. The unit is provided 20 additional hours to perform this task over and above the 4 hours allowed by either Action A.1.1 or Action A.1.2.1. The Completion Time of 24 hours is acceptable because of the increase in the DNB margin, which is obtained at lower power levels, and the low probability of having a DNB limiting event within this 24 hour period. Additionally, operating experience has indicated that this Completion Time is sufficient to obtain the incore flux map, perform the required calculations, and evaluate $F^N_{\Delta H}$. A single performance of SR 3.2.2.1 may be used to satisfy requirements of both Required Action A.2 and A.3, if it is completed within 24 hours of entering Condition A.

A.3

Verification that $F^N_{\Delta H}$ is within its specified limits after an out of limit occurrence ensures that the cause that led to the $F^N_{\Delta H}$ exceeding its limit is corrected, and that subsequent operation proceeds within the LCO limit. This Action demonstrates that the $F^N_{\Delta H}$ limit is within the LCO limits prior to exceeding 50% RTP, again prior to exceeding 75% RTP, and within 24 hours after THERMAL POWER is ≥ 95% RTP. A single performance of SR 3.2.2.1 may be used to satisfy requirements of both Required Action A.2 and A.3, if it is completed within 24 hours of entering Condition A.

This Required Action is modified by a Note that states that THERMAL POWER does not have to be reduced prior to performing this Action.

3.2 POWER DISTRIBUTION LIMITS

3.2.3 AXIAL FLUX DIFFERENCE (AFD) (Constant Axial Offset Control (CAOC) Methodology)

LCO 3.2.3 The AFD:

a. Shall be maintained within the target band about the target flux difference. The target band is specified in the COLR.

b. May deviate outside the target band with THERMAL POWER < 90% RTP but ≥ 50% RTP, provided AFD is within the acceptable operation limits and cumulative penalty deviation time is ≤ 1 hour during the previous 24 hours. The acceptable operation limits are specified in the COLR.

c. May deviate outside the target band with THERMAL POWER < 50% RTP.

- NOTES -

1. The AFD shall be considered outside the target band when two or more OPERABLE excore channels indicate AFD to be outside the target band.

2. With THERMAL POWER ≥ 50% RTP, penalty deviation time shall be accumulated on the basis of a 1 minute penalty deviation for each 1 minute of power operation with AFD outside the target band.

3. With THERMAL POWER < 50% RTP and > 15% RTP, penalty deviation time shall be accumulated on the basis of a 0.5 minute penalty deviation for each 1 minute of power operation with AFD outside the target band.

4. A total of 16 hours of operation may be accumulated with AFD outside the target band without penalty deviation time during surveillance of power range channels in accordance with SR 3.3.1.6, provided AFD is maintained within acceptable operation.

APPLICABILITY: MODE 1 with THERMAL POWER > 15% RTP.

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
	A.4	Reevaluate safety analyses and confirm results remain valid for duration of operation under this condition.	Prior to increasing THERMAL POWER above the limit of Required Action A.1
	AND		
	A.5	- NOTES - 1. Perform Required Action A.5 only after Required Action A.4 is completed. 2. Required Action A.6 shall be completed whenever Required Action A.5 is performed. Normalize excore detectors to restore QPTR to within limit.	Prior to increasing THERMAL POWER above the limit of Required Action A.1
	AND		
	A.6	- NOTE - Perform Required Action A.6 only after Required Action A.5 is completed. Perform SR 3.2.1.1 and SR 3.2.2.1.	Within 24 hours after achieving equilibrium conditions at RTP not to exceed 48 hours after increasing THERMAL POWER above the limit of Required Action A.1

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.4 QUADRANT POWER TILT RATIO (QPTR)

BASES

BACKGROUND

The QPTR limit ensures that the gross radial power distribution remains consistent with the design values used in the safety analyses. Precise radial power distribution measurements are made during startup testing, after refueling, and periodically during power operation.

The power density at any point in the core must be limited so that the fuel design criteria are maintained. Together, LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," LCO 3.2.4, and LCO 3.1.6, "Control Bank Insertion Limits," provide limits on process variables that characterize and control the three dimensional power distribution of the reactor core. Control of these variables ensures that the core operates within the fuel design criteria and that the power distribution remains within the bounds used in the safety analyses.

APPLICABLE SAFETY ANALYSES

This LCO precludes core power distributions that violate the following fuel design criteria:

a. During a large break loss of coolant accident, the peak cladding temperature must not exceed 2200°F (Ref. 1),

b. During a loss of forced reactor coolant flow accident, there must be at least 95% probability at the 95% confidence level (the 95/95 departure from nucleate boiling (DNB) criterion) that the hottest fuel rod in the core does not experience a DNB condition,

c. During an ejected rod accident, the energy deposition to the fuel must not exceed 200 cal/gm (Ref. 2), and

d. The control rods must be capable of shutting down the reactor with a minimum required SDM with the highest worth control rod stuck fully withdrawn (Ref. 3).

The LCO limits on the AFD, the QPTR, the Heat Flux Hot Channel Factor ($F_Q(Z)$), the Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$), and control bank insertion are established to preclude core power distributions that exceed the safety analyses limits.

BASES

BACKGROUND (continued)

Technical specifications contain values related to the OPERABILITY of equipment required for safe operation of the facility. OPERABLE is defined in technical specifications as "...being capable of performing its safety functions(s)." For automatic protective devices, the required safety function is to ensure that a SL is not exceeded and therefore the LSSS as defined by 10 CFR 50.36 is the same as the OPERABILITY limit for these devices. However, use of the trip setpoint to define OPERABILITY in technical specifications and its corresponding designation as the LSSS required by 10 CFR 50.36 would be an overly restrictive requirement if it were applied as an OPERABILITY limit for the "as found" value of a protective device setting during a surveillance. This would result in technical specification compliance problems and reports and corrective actions required by the rule which are not necessary to ensure safety. For example, an automatic protective device with a setting that has been found to be different from the trip setpoint due to some drift of the setting may still be OPERABLE since drift is to be expected. This expected drift would have been specifically accounted for in the setpoint methodology for calculating the trip setpoint and thus the automatic protective action would still have ensured that the SL would not be exceeded with the "as found" setting of the protective device. Therefore, the device would still be OPERABLE since it would have performed its safety function and the only corrective action required would be to reset the device to the trip setpoint to account for further drift during the next surveillance interval.

There is also some point beyond which the device would have not been able to perform its function due, for example, to greater than expected drift. This value needs to be specified in the technical specifications in order to define OPERABILITY of the devices and is designated as the Allowable Value which, as stated above, is the same as the LSSS.

The Allowable Value specified in Table 3.3.1-1 serves as the LSSS such that a channel is OPERABLE if the actuation point is found not to exceed the Allowable Value during the CHANNEL OPERATIONAL TEST (COT). As such, the Allowable Value differs from the limiting setpoint by an amount primarily equal to the expected instrument loop uncertainties, such as drift and calibration effect, during the surveillance interval. In this manner, the actual setting of the device will still meet the LSSS definition and ensure that a Safety Limit is not exceeded at any given point of time as long as the device has not drifted beyond that expected during the surveillance interval. Note that, although the channel is "OPERABLE" under these circumstances, the trip setpoint should be left adjusted to a value within the established trip setpoint calibration tolerance band, in accordance with uncertainty

BASES

BACKGROUND (continued)

assumptions stated in the referenced setpoint methodology (as-left criteria), and confirmed to be operating within the statistical allowances of the uncertainty terms assigned. If the actual setting of the device is found to have exceeded the as-found allowance, the channel would be evaluated to determine Technical Specification OPERABILITY. The results of this evaluation would result in corrective action including those actions required by 10 CFR 50.36 when automatic protective devices do not function as required.

Allowable Values for each RPS function are listed in Table 3.3.1-1. Trip Setpoints that ensure that the Allowable Values are not exceeded over the calibration interval are controlled administratively outside of the Technical Specifications.

During AOOs, which are those events expected to occur one or more times during the unit life, the acceptable limits are:

1. The Departure from Nucleate Boiling Ratio (DNBR) shall be maintained above the Safety Limit (SL) value to prevent departure from nucleate boiling (DNB),
2. Fuel centerline melt shall not occur, and
3. The RCS pressure SL of 2735 psig shall not be exceeded.

Operation within the SLs of Specification 2.0, "Safety Limits (SLs)," also maintains the above values and assures that offsite dose will be within the 10 CFR 50.67 criteria during AOOs.

Accidents are events that are analyzed even though they are not expected to occur during the unit life. The acceptable limit during accidents is that offsite dose shall be maintained within 10 CFR 50.67 limits. 10 CFR 50.67 limits are used in the evaluation of proposed design basis changes with respect to potential reactor accidents of exceedingly low probability of occurrence and low risk of public exposure to radiation. Meeting the acceptable dose limit for an accident category is considered having acceptable consequences for that event.

The RPS instrumentation is segmented into four distinct but interconnected modules as identified below:

BASES

BACKGROUND (continued)

1. Field transmitters or process sensors: provide a measurable electronic signal based upon the physical characteristics of the parameter being measured,

2. Signal Process Control and Protection System, including Analog Protection System, Nuclear Instrumentation System (NIS), field contacts, and protection channel sets: provides signal conditioning, bistable setpoint comparison, process algorithm actuation, compatible electrical signal output to protection system devices, and control board/control room/miscellaneous indications,

3. RPS Automatic Trip Logic, including input, logic, and output: initiates proper reactor shutdown and/or ESF actuation in accordance with the defined logic, which is based on the bistable outputs from the signal process control and protection system, and

4. Reactor trip switchgear, including reactor trip breakers (RTBs) and bypass breakers: provide the means to interrupt power to the control rod drive mechanisms (CRDMs) and allows the rod cluster control assemblies (RCCAs), or "rods," to fall into the core and shut down the reactor. The bypass breakers allow testing of the RTBs at power.

<u>Field Transmitters or Sensors</u>

To meet the design demands for redundancy and reliability, more than one, and often as many as four, field transmitters or sensors are used to measure unit parameters. In many cases, field transmitters or sensors that input to the Reactor Protection System (RPS) are shared with the Engineered Safety Feature Actuation System (ESFAS). In some cases, the same channels also provide control system inputs.

To account for the calibration tolerances and instrument drift, which are assumed to occur between calibrations, statistical allowances are provided in the trip setpoint. The OPERABILITY of each transmitter or sensor is determined by either "as-found" calibration data evaluated during the CHANNEL CALIBRATION or by qualitative assessment of field transmitter or sensor as related to the channel behavior observed during performance of the CHANNEL CHECK.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

OPERABILITY in MODE 1 ensures the Function is available to perform its decreasing power Functions in the event of a reactor shutdown. This Function must be OPERABLE in MODE 2 to ensure that core protection is provided during a startup or shutdown by the Power Range Neutron Flux - Low and Intermediate Range Neutron Flux reactor trips. In MODE 3, 4, 5, or 6, this Function does not have to be OPERABLE because the reactor is not at power and the Source Range Neutron Flux reactor trip provides core protection.

e. Turbine First Stage Pressure

The Turbine First Stage Pressure (P-7 input) interlock is actuated when the pressure in the first stage of the high pressure turbine is greater than approximately 10% of the pressure consistent with 100% RTP. This is determined by one-out-of-two pressure detectors. The LCO requirement for this Function ensures that one of the inputs to the P-7 interlock is available.

The LCO requires two channels of Turbine First Stage Pressure interlock to be OPERABLE in MODE 1.

The Turbine First Stage Pressure (P-7 input) interlock must be OPERABLE when the turbine generator is operating. The interlock Function is not required OPERABLE in MODE 2, 3, 4, 5, or 6 because the turbine generator is not operating.

18. Reactor Trip Breakers

This trip Function applies to the RTBs exclusive of undervoltage and shunt trip mechanisms which are addressed in Function 19. The LCO requires two OPERABLE trains of trip breakers. A trip breaker train consists of all trip breakers associated with a single RPS logic train that are racked in, closed, and capable of supplying power to the Rod Control System. Thus, the train may consist of the main breaker, bypass breaker, or main breaker and bypass breaker, depending upon the system configuration.

BASES

ACTIONS (continued)

The Completion Time of 48 hours is reasonable considering that there are two automatic actuation trains and another manual initiation channel OPERABLE, and the low probability of an event occurring during this interval.

If the Manual Reactor Trip Function cannot be restored to OPERABLE status within the allowed 48 hour Completion Time, the unit must be brought to a MODE in which the requirement does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 additional hours (54 hours total time). The 6 additional hours to reach MODE 3 is reasonable, based on operating experience, to reach MODE 3 from full power operation in an orderly manner and without challenging unit systems. With the unit in MODE 3, ACTION C would apply to any inoperable Manual Reactor Trip Function if the Rod Control System is capable of rod withdrawal or one or more rods are not fully inserted.

<u>C.1, C.2.1, and C.2.2</u>

Condition C applies to the following reactor trip Functions in MODE 3, 4, or 5 with the Rod Control System capable of rod withdrawal or one or more rods not fully inserted:

- Manual Reactor Trip,
- RTBs,
- RTB Undervoltage and Shunt Trip Mechanisms, and
- Automatic Trip Logic.

This action addresses the train orientation of the RPS Automatic Trip Logic for these Functions. With one channel or train inoperable, the inoperable channel or train must be restored to OPERABLE status within 48 hours. If the affected Function(s) cannot be restored to OPERABLE status within the allowed 48 hour Completion Time, the unit must be placed in a MODE in which the requirement does not apply. To achieve this status, action must be initiated within the same 48 hours to ensure that all rods are fully inserted, and the Rod Control System must be placed in a condition incapable of rod withdrawal within the next hour. The additional hour provides sufficient time to accomplish the action in an orderly manner. With rods fully inserted and the Rod Control System incapable of rod withdrawal, these Functions are no longer required.

BASES

ACTIONS (continued)

If the inoperable channel cannot be placed in the trip condition within the specified Completion Time, the unit must be placed in a MODE where these Functions are not required OPERABLE. An additional 6 hours is allowed to place the unit in MODE 3. Six hours is a reasonable time, based on operating experience, to place the unit in MODE 3 from full power in an orderly manner and without challenging unit systems.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to 12 hours while performing routine surveillance testing (including associated repairs). The 12 hour time limit is justified in Reference 7. This allowance may be used to bypass an inoperable channel that is in trip to permit surveillance testing (including associated repairs) and setpoint adjustment of other channels. This allowance may also be used to bypass an otherwise OPERABLE channel during surveillance testing and setpoint adjustment.

<u>F.1 and F.2</u>

Condition F applies to the Intermediate Range Neutron Flux trip when THERMAL POWER is above the P-6 setpoint and below the P-10 setpoint and one channel is inoperable. Above the P-6 setpoint and below the P-10 setpoint, the NIS intermediate range detector performs the monitoring Functions. If THERMAL POWER is greater than the P-6 setpoint but less than the P-10 setpoint, 24 hours is allowed to reduce THERMAL POWER below the P-6 setpoint or to increase THERMAL POWER above the P-10 setpoint. The NIS Intermediate Range Neutron Flux channels must be OPERABLE when the power level is above the capability of the source range, P-6, and below the capability of the power range, P-10. If THERMAL POWER is greater than the P-10 setpoint, the NIS power range detectors perform the monitoring and protection functions and the intermediate range is not required. The Completion Times allow for a slow and controlled power adjustment above P-10 or below P-6 and take into account the redundant capability afforded by the redundant OPERABLE channel, and the low probability of its failure during this period. This action does not require the inoperable channel to be tripped because the Function uses one-out-of-two logic. Tripping one channel would trip the reactor. Thus, the Required Actions specified in this Condition are only applicable when channel failure does not result in reactor trip.

BASES

ACTIONS (continued)

- RCP Breaker Position,
- RCP Undervoltage, and
- RCP Underfrequency.

With one channel inoperable, the inoperable channel must be placed in the tripped condition within 72 hours. For the Pressurizer Pressure - Low, Pressurizer Water Level - High, Undervoltage RCPs, and Underfrequency RCPs trip Functions, placing the channel in the tripped condition when above the P-7 setpoint results in a condition requiring only one additional channel to initiate a reactor trip. For the Reactor Coolant Flow - Low trip Function, placing the channel in the tripped condition when above the P-8 setpoint results in a partial trip condition requiring only one additional channel in the same loop to initiate a reactor trip. Two tripped channels in two RCS loops are required to initiate a reactor trip when below the P-8 setpoint and above the P-7 setpoint. These Functions do not have to be OPERABLE below the P-7 setpoint because there are no loss of flow trips below the P-7 setpoint. There is insufficient heat production to generate DNB conditions below the P-7 setpoint. The 72 hours allowed to place the channel in the tripped condition is justified in Reference 8. An additional 6 hours is allowed to reduce THERMAL POWER to below P-7 if the inoperable channel cannot be restored to OPERABLE status or placed in trip within the specified Completion Time.

Allowance of this time interval takes into consideration the redundant capability provided by the remaining redundant OPERABLE channel, and the low probability of occurrence of an event during this period that may require the protection afforded by the Functions associated with Condition K.

The Required Actions have been modified by a Note that allows placing one channel in the bypassed condition for up to 12 hours while performing routine surveillance testing. The 12 hour time limit is justified in Reference 7. This allowance may be used to bypass an inoperable channel that is in trip to permit surveillance testing and setpoint adjustment of other channels. This allowance may also be used to bypass an otherwise OPERABLE channel during surveillance testing and setpoint adjustment.

BASES

ACTIONS (continued)

L.1 and L.2

Condition L applies to the RCP Breaker Position (Single Loop) reactor trip Function. There is one breaker position device per RCP breaker. With one channel inoperable, the inoperable channel must be restored to OPERABLE status within 6 hours. If the channel cannot be restored to OPERABLE status within the 6 hours, then THERMAL POWER must be reduced below the P-8 setpoint within the next 4 hours.

This places the unit in a MODE where the LCO is no longer applicable. This Function does not have to be OPERABLE below the P-8 setpoint because other RPS Functions provide core protection below the P-8 setpoint. The 6 hours allowed to restore the channel to OPERABLE status and the 4 additional hours allowed to reduce THERMAL POWER to below the P-8 setpoint are justified in Reference 8.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to 4 hours while performing online surveillance testing of the other channels. The 4 hour time limit is justified in Reference 8. This allowance may be used to bypass an inoperable channel that is in trip to permit surveillance testing (including associated repairs) of the other channels.

M.1 and M.2

Condition M applies to the RCP Breaker Position (Two Loops) reactor trip Function. There is one breaker position device per RCP breaker. With one channel inoperable, the inoperable channel must be placed in trip within 6 hours. If the channel cannot be placed in trip within the 6 hours, then THERMAL POWER must be reduced below the P-7 setpoint within the next 6 hours. This places the unit in a MODE where the LCO is no longer applicable.

This Function does not have to be OPERABLE below the P-7 setpoint because other RPS Functions provide core protection below the P-7 setpoint. The 6 hours allowed to place the channel in trip and the 6 additional hours allowed to reduce THERMAL POWER to below the P-7 setpoint are justified in Reference 8. The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to 4 hours while performing routine surveillance testing of the other channels. The 4 hour time limit is justified in Reference 8.

BASES

ACTIONS (continued)

The 24 hour time limit for the RPS Automatic Trip Logic train testing and maintenance is greater than the 4 hour time limit for RTBs, which the logic trains supports. The longer time limit for the Logic train (24 hours) is acceptable based on Reference 7.

P.1 and P.2

Condition P applies to the RTBs in MODES 1 and 2. These actions address the train orientation of the RPS for the RTBs. With one train inoperable, 24 hours is allowed for train corrective maintenance to restore the train to OPERABLE status or the unit must be placed in MODE 3 within the next 6 hours. The 24 hour Completion Time is justified in Reference 10. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems. Placing the unit in MODE 3 results in ACTION C entry while RTB(s) are inoperable.

The Required Actions have been modified by a Note that allows one train to be bypassed for up to 4 hours for surveillance testing, provided the other train is OPERABLE. This Note applies to RTB testing that is performed independently from the corresponding Logic train testing. For concurrent testing of the Logic and RTB, the 24 hour test time limit of Condition O applies. The 24 hour time is justified in Ref. 10.

Q.1 and Q.2

Condition Q applies to the P-6 and P-10 interlocks. With one or more channels or trains inoperable for one-out-of-two or two-out-of-four coincidence logic, the associated interlock must be verified to be in its required state for the existing unit condition within 1 hour or the unit must be placed in MODE 3 within the next 6 hours. Verifying the interlock status manually accomplishes the interlock's Function. The Completion Time of 1 hour is based on operating experience and the minimum amount of time allowed for manual operator actions. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems. The 1 hour and 6 hour Completion Times are equal to the time allowed by LCO 3.0.3 for shutdown actions in the event of a complete loss of RPS Function.

BASES

ACTIONS (continued)

R.1 and R.2

Condition R applies to the P-7 and P-8 interlocks and the input to P-7 from turbine first stage pressure. With one or more channels or trains inoperable for one-out-of-two or two-out-of-four coincidence logic, the associated interlock must be verified to be in its required state for the existing unit condition within 1 hour or the unit must be placed in MODE 2 within the next 6 hours. These actions are conservative for the case where power level is being raised. Verifying the interlock status manually accomplishes the interlock's Function. The Completion Time of 1 hour is based on operating experience and the minimum amount of time allowed for manual operator actions. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 2 from full power in an orderly manner and without challenging unit systems.

S.1 and S.2

Condition S applies to the RTB Undervoltage and Shunt Trip Mechanisms, or diverse trip features, in MODES 1 and 2. With one of the diverse trip features inoperable, it must be restored to an OPERABLE status within 48 hours or the unit must be placed in a MODE where the requirement does not apply. This is accomplished by placing the unit in MODE 3 within the next 6 hours (54 hours total time). The Completion Time of 6 hours is a reasonable time, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems. With the unit in MODE 3, ACTION C would apply to any inoperable RTB trip mechanism.

The Completion Time of 48 hours for Required Action S.1 is reasonable considering that in this Condition there is one remaining diverse feature for the affected RTB, and one OPERABLE RTB capable of performing the safety function and given the low probability of an event occurring during this interval.

SURVEILLANCE REQUIREMENTS

The SRs for each RPS Function are identified by the SRs column of Table 3.3.1-1 for that Function.

A Note has been added to the SR Table stating that Table 3.3.1-1 determines which SRs apply to which RPS Functions.

BASES

SURVEILLANCE REQUIREMENTS (continued)

A Note modifies SR 3.3.1.6. The Note states that this Surveillance is required only if reactor power is > 50% RTP and that 24 hours is allowed for performing the first surveillance after reaching 50% RTP.

The Frequency of 92 EFPD is adequate based on industry operating experience, considering instrument reliability and operating history data for instrument drift. Additionally, this Frequency is consistent with the Frequency of SR 3.2.3.3 which measures the target flux differences and adjusts the target flux difference for each excore channel to the value measured at steady state conditions. The Frequency of 92 EFPDs recognizes that the target flux difference varies slowly with core burnup.

SR 3.3.1.7

SR 3.3.1.7 is the performance of a COT every 184 days.

A COT is performed on each required channel to ensure the entire channel will perform the intended Function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL OPERATIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

Setpoints must be within the Allowable Values specified in Table 3.3.1-1. The "as found" and "as left" values must also be recorded and reviewed for consistency with the assumptions of References 7 and 8. The difference between the current "as found" values and the previous test "as left" values must be consistent with the drift allowance used in the setpoint methodology. The setpoint shall be left set consistent with the assumptions of Reference 6 which incorporates the requirements of References 7 and 8.

SR 3.3.1.7 is modified by a Note that provides a 4 hour delay in the requirement to perform this Surveillance for source range instrumentation when entering MODE 3 from MODE 2. This Note allows a normal shutdown to proceed without a delay for testing in MODE 2 and for a short time in MODE 3 until the RTBs are open and SR 3.3.1.7 is no longer required to be performed. If the unit is to be in MODE 3 with the RTBs closed for > 4 hours this Surveillance must be performed prior to 4 hours after entry into MODE 3.

The Frequency of 184 days is justified in Reference 10.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.9

SR 3.3.1.9 is the performance of a TADOT and is performed every 92 days, as justified in Reference 7. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable TADOT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

The SR is modified by a Note that excludes verification of setpoints from the TADOT. Since this SR applies to RCP undervoltage and underfrequency relays, setpoint verification requires elaborate bench calibration and is accomplished during the CHANNEL CALIBRATION.

SR 3.3.1.10

A CHANNEL CALIBRATION is performed every 24 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 a measured parameter within the necessary range and accuracy.

CHANNEL CALIBRATIONS must be performed consistent with the assumptions used in Reference 6. The difference between the current "as found" values and the previous test "as left" values must be consistent with the drift allowance used in the setpoint methodology.

The Frequency of 24 months is based on the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint methodology.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.13

SR 3.3.1.13 is the performance of a COT of RPS interlocks every 24 months. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL OPERATIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

The Frequency is based on the known reliability of the interlocks and the multichannel redundancy available, and has been shown to be acceptable through operating experience.

SR 3.3.1.14

SR 3.3.1.14 is the performance of a TADOT of the Manual Reactor Trip, RCP Breaker Position, Turbine Trip Low Auto Stop Oil Pressure, and the SI Input from ESFAS. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable TADOT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. This TADOT is performed every 24 months. The test shall independently verify the OPERABILITY of the tested functions including overlap with the undervoltage and shunt trip mechanisms for the Manual Reactor Trip Function for the Reactor Trip Breakers and Reactor Trip Bypass Breakers up to and including matrix contacts of RT-11/RT-12 from both manual trip actuating devices. The Reactor Trip Bypass Breaker test shall include testing of the automatic undervoltage trip and the shunt trip through the trip actuating devices.

The Frequency is based on the known reliability of the Functions and the multichannel redundancy available, and has been shown to be acceptable through operating experience.

The SR is modified by a Note that excludes verification of setpoints from the TADOT. Except for Turbine Trip Low Auto Stop Oil Pressure, the Functions affected have no setpoints associated with them.

2.3 LIMITING SAFETY SYSTEM SETTINGS, PROTECTIVE INSTRUMENTATION

A.2

~~Applicability~~

~~Applies to trip settings for instruments monitoring reactor power and reactor coolant pressure, temperature, flow, and pressurizer level.~~

~~Objective~~

~~To provide for automatic protective action such that the principal process variables do not exceed a safety limit.~~

Specifications

LA.6 — allowable values — A.X.f

1. Protective instrumentation for reactor trip ~~settings~~ shall be as follows:

A. Startup protection

LA.6 — 29.6% — A.5.f

T 3.3.1-1, #2b (1) High flux, power range (low setpoint): ≤ 25% of rated power. A.5

B. Core limit protection

LA.6 — 112.6% — A.4.f

T3.3.1-1, #2a (1) High flux, power range (high setpoint): ≤ 109% of rated power. A.4

LA.6

T3.3.1-1, #7b (2) High pressurizer pressure: ≤ 2363 psig. 2416 — A.11.f A.11

T3.3.1-1, #7a (3) Low pressurizer pressure: ≥ 1928 psig. 1878 — A.10.f A.10

T3.3.1-1, #5 (4) Overtemperature ΔT: LA.6 A.8

T3.3.1-1 Note 1

$$\Delta T \le \Delta T_o \left[K_1 - K_2 \frac{1+\tau_1 S}{1+\tau_2 S}(T - T') + K_3 (P - P') - f(\Delta I)\right]$$

A.8.f A.8.f

where:

ΔT = Measured ΔT by hot and cold leg RTDs, °F ≤3.3% of ΔT span

ΔT_o ≤ Indicated ΔT at rated power, °F A.8

T = Average temperature, °F

T' = Design full power T_{avg} at rated power, ≤ 579.2°F — LA.5

τ_1: seconds
τ_2: seconds
S = Laplace Transform, sec^{-1}
A.8.f

A.6.f

T 3.3.1-1, #3 IRM allowable value ≤31.4% RTP — M.18

T3.3.1-1, #4 SRM allowable value ≤9.7E5 cps — M.18

A.7.f

P = Pressurizer pressure, psig

P' = 2235 psig

$K_1 \le 1.22$

$K_2 = 0.022$

$K_3 = 0.00095$

LA.5

A.8

and $f(\Delta I)$ is a function of the indicated difference between top and bottom detectors of the power-range nuclear ion chambers; with gains to be selected based on measured instrument response during plant startup tests such that:

LA.4

T 3.3.1-1, Note 1

(i) ~~For $q_t - q_b$ between -36% and +7%, $f(\Delta I) = 0$, where q_t and q_b are percent rated power in the top and bottom halves of the core respectively, and $q_t + q_b$ is total power in percent of rated power;~~

(ii) ~~For each percent that the magnitude of $q_t - q_b$ exceeds -36%, the ΔT trip setpoint shall be automatically reduced by 2.14% of its value at rated power; and~~

(iii) ~~For each percent that the magnitude of $q_t - q_b$ exceeds +7%, the ΔT trip setpoint shall be automatically reduced by 2.15% of its value at rated power.~~

LA.5

T 3.3.1-1, #6

(5) Overpower ΔT:

T 3.3.1-1, Note 2

$$\Delta T \le \Delta T_o \left[K_4 - K_5 \boxed{\frac{dT}{dt}} - K_6 (T - T'')\right]$$

$\le 2.3\%$ of ΔT span — A.9.f

$\frac{\tau_3 s}{1 + \tau_3 s}$ — A.9.f

A.9

where:

ΔT = Measured ΔT by hot and cold leg RTDs, °F

$\Delta T_o \le$ Indicated ΔT at rated power, °F

T = Average temperature, °F

T3.3.1-1, Note 2

T" = Indicated full power T_{avg} at rated power ≤ 579.2°F

K_4 ≤ 1.074

K_5 = Zero for decreasing average temperature

K_5 ≥ 0.188, for increasing average temperature (sec/°F)

K_6 ≥ 0.0015 for T ≥T"; K_6 = 0 for T < T"

LA.5 A.9

$\frac{dT}{dt}$ = Rate of change of T_{avg}

T3.3.1-1, #9 (6) Low reactor coolant loop flow:

LA.6 88.8 A.13.f

(a) ≥ 92% of normal indicated loop flow. A.13

T3.3.1-1, #12 (b) Low reactor coolant pump frequency: ≥ 57.5 cps. A.17

LA.6 57.1 A.17.f

T3.3.1-1, #11 (7) Undervoltage: ≥ 70% of normal voltage. A.16

LA.6 ≥4959.4V A.16.f

C. Other reactor trips

LA.6 96.9 A.12.f

T3.3.1-1, #8 (1) High pressurizer water level: ≤ 90% of span. A.12

T3.3.1-1, #13 (2) Low-low steam generator water level: ≥ 7% of narrow range instrument span. A.18

LA.6 3.7% A.18.f

LA.6

T3.3.1-1, #17 2. Protective instrumentation ~~settings~~ Allowable Values A.X.f for reactor trip interlocks shall satisfy the following conditions:

T3.3.1-1, #7a, #8, #10b, #11, #12 Notes (e) and (g) A. The reactor trips on low pressurizer pressure, high pressurizer level, and low reactor coolant flow for two or more loops shall be ~~un~~blocked when: A.10 A.12 A.15

≥ 10% RTP (set) ≥ 3.6% RTP (reset) A.10.f A.12.f A.15.f A.25.f A.26.f

T3.3.1-1, #17d (1) ~~Power range nuclear flux ≥ 10% of rated power~~ or P-7 A.25

T3.3.1-1, #17e (2) Turbine first stage pressure ≥ 10% of equivalent full load. A.26

P-7 input LA.6 9.25% A.26.f

T3.3.1-1, #17c T3.3.1-1, #10a and Note (f) B. The single loop loss of flow reactor trip may be bypassed when the power range nuclear instrumentation ~~indicates ≤ 60% of rated power~~ A.24

< P-8 setpoint A.14

Discussions of Changes:

A.04.f 3.3.1: Reactor Protection System (RPS) Instrumentation

Rev. 7 Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.1, Function 2.a, Power Range Neutron Flux-High.

Description of Change

CTS 2.3.1.B(1) establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the Power Range Neutron Flux-High. As described in the Bases for CTS 3.5, IP2 uses the combination of this nominal trip setpoint and an associated 'administrative limit' which is controlled outside of the Technical Specifications to establish trip function Operability. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

ITS 3.3.1, Function 2.a, Power Range Neutron Flux-High, will use the CTS "administrative limit," which is equivalent to the current licensing basis "Allowable Value," (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS). Use of the "Allowable Value," as the LSSS required to be in the Technical Specifications by 10 CFR 50.36(c)(1), is consistent with the guidance provided in Regulatory Guide 1.105, 'Setpoints for Safety-Related Instrumentation.'

In conjunction with the change which will include the allowable value in the ITS, IP2 will elect the option described in STS (NUREG-1431) to maintain the nominal trip setpoint (i.e., as-left limit) in a licensee controlled document. Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.6.

Justification for Change

Using the CTS "administrative limit" (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS) is an administrate change with no impact on safety. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.6.

A.05.f **3.3.1: Reactor Protection System (RPS) Instrumentation**

Rev. 7 Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.1, Function 2.b, Power Range Neutron Flux-Low.

Description of Change

CTS 2.3.1.A (1) establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the Power Range Neutron Flux-Low trip at less than or equal to 25% RTP. As described in the Bases for CTS 3.5, IP2 uses the combination of this nominal trip setpoint and an associated 'administrative limit' which is controlled outside of the Technical Specifications to establish trip function Operability. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

ITS 3.3.1, Function 2.b, Power Range Neutron Flux-Low, will use the CTS "administrative limit," which is equivalent to the current licensing basis "Allowable Value," (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS). Use of the "Allowable Value," as the LSSS required to be in the Technical Specifications by 10 CFR 50.36(c)(1), is consistent with the guidance provided in Regulatory Guide 1.105, 'Setpoints for Safety-Related Instrumentation.'

In conjunction with the change which will include the allowable value in the ITS, IP2 will elect the option described in STS (NUREG-1431) to maintain the nominal trip setpoint (i.e., as-left limit) in a licensee controlled document. Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.6.

Justification for Change

Using the CTS "administrative limit" (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS) is an administrate change with no impact on safety. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.6.

A.06.f 3.3.1: Reactor Protection System (RPS) Instrumentation

Rev. 7 Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.1, Function 3, Intermediate Range Neutron Flux.

Description of Change

CTS 2.3 does not establish a limiting safety system setting (allowable value) for the IRM Flux (trip) function although the trip must be set above the P-10 setpoint and is typically set below the Power Range Neutron Flux - Low trip setpoint (i.e. approximately 25% RTP) so that the IRM trip anticipates the Power Range Neutron Flux - Low trip.

ITS 3.3.1, Function 3, Intermediate Range Neutron Flux, will use the CTS "administrative limit," which is equivalent to the current licensing basis "Allowable Value," (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS). Use of the "Allowable Value," as the LSSS required to be in the Technical Specifications by 10 CFR 50.36(c)(1), is consistent with the guidance provided in Regulatory Guide 1.105, 'Setpoints for Safety-Related Instrumentation.' Inclusion in the ITS of a specific limit for the allowable value for this function is a more restrictive change that is addressed in DOC M.18.

Justification for Change

Inclusion in the ITS of a specific limit for the allowable value for this function is a more restrictive change that is addressed in DOC M.18.

Using the CTS "administrative limit" (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS) is an administrate change with no impact on safety. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

A.07.f <u>3.3.1: Reactor Protection System (RPS) Instrumentation</u>

Rev. 7 <u>Category</u> Administrative: No Technical Changes

<u>DOC Summary:</u>

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.1, Function 4, Source Range Neutron (SRM) Flux.

<u>Description of Change</u>

CTS 2.3 does not establish a limiting safety system setting (allowable value) for the Source Range Flux (trip) function although it is typically set near the upper end of the source range indication.

LCO 3.3.1, Function 2.b, Power Range Neutron Flux-Low, will use the CTS "administrative limit," which is equivalent to the current licensing basis "Allowable Value," (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS). Use of the "Allowable Value," as the LSSS required to be in the Technical Specifications by 10 CFR 50.36(c)(1), is consistent with the guidance provided in Regulatory Guide 1.105, 'Setpoints for Safety-Related Instrumentation.' Inclusion in the ITS of a specific limit for the allowable value for this function is a more restrictive change that is addressed in DOC M.18.

<u>Justification for Change</u>

Inclusion in the ITS of a specific limit for the allowable value for this function is a more restrictive change that is addressed in DOC M.18.

Using the CTS "administrative limit" (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS) is an administrate change with no impact on safety. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

A.08.f 3.3.1: Reactor Protection System (RPS) Instrumentation

Rev. 7 Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.1, Function 5, Overtemperature delta T.

Description of Change

CTS 2.3.1.B(4) establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the Overtemperature delta T function based on a calculation that includes input from various parameters as described in CTS 2.3.1.B(4). As described in the Bases for CTS 3.5, IP2 uses the combination of this nominal trip setpoint and an associated 'administrative limit' which is controlled outside of the Technical Specifications to establish trip function Operability. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

ITS 3.3.1, Function 5 (and associated acceptance criteria in Table 3.3.1-1, Note 1), uses the same inputs, equation and constants used in the CTS with the following differences:

a. ITS 3.3.1, Function 5 (and associated acceptance criteria in Table 3.3.1-1, Note 1), will use the CTS "administrative limit," which is equivalent to the current licensing basis "Allowable Value," (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS). Use of the "Allowable Value," as the LSSS required to be in the Technical Specifications by 10 CFR 50.36(c)(1), is consistent with the guidance provided in Regulatory Guide 1.105, 'Setpoints for Safety-Related Instrumentation.'

b. ITS 3.3.1, Function 5, acceptance criteria in Note 1 are modified to explicitly require that Laplace transform operators that model system response and the associated Tau values, the electronic dynamic compensation time constants, are set at the required values. Inclusion of this acceptance criteria in the ITS is an administrative change with no impact on safety because this acceptance criteria is consistent with current analysis assumptions and procedural requirements.

Justification for Change

Using the CTS "administrative limit" (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS) is an administrate change with no impact on safety. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.6.

A.09.f 3.3.1: Reactor Protection System (RPS) Instrumentation

Rev. 7 Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.1, Function 6, Overpower delta T.

Description of Change

CTS 2.3.1.B(5) establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the Overpower delta T function based on a calculation that includes input from RCS Temperature as described in CTS 2.3.1.B(5). As described in the Bases for CTS 3.5, IP2 uses the combination of this nominal trip setpoint and an associated 'administrative limit' which is controlled outside of the Technical Specifications to establish trip function Operability. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

ITS 3.3.1, Function 6 (and associated acceptance criteria in Table 3.3.1-1, Note 2), uses the same equation and constants used in the CTS with the following difference. ITS 3.3.1, Function 6 (and associated acceptance criteria in Table 3.3.1-1, Note 2), will use the CTS "administrative limit," which is equivalent to the current licensing basis "Allowable Value," (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS). Use of the "Allowable Value," as the LSSS required to be in the Technical Specifications by 10 CFR 50.36(c)(1), is consistent with the guidance provided in Regulatory Guide 1.105, 'Setpoints for Safety-Related Instrumentation.'

In conjunction with the change which will include the allowable value in the ITS, IP2 will elect the option described in STS (NUREG-1431) to maintain the nominal trip setpoint (i.e., as-left limit) in a licensee controlled document.

Additionally, ITS replaces the differential used to denote the rate of change of temperature with respect to time with the more commonly used Laplace transform.

Justification for Change

Using the CTS "administrative limit" (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS) is an administrate change with no impact on safety. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.6.

A.10.f 3.3.1: Reactor Protection System (RPS) Instrumentation

Rev. 7 Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.1, Function 7.a, Pressurizer Pressure-Low.

Description of Change

CTS 2.3.1.B (3) establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the Low Pressurizer Pressure function at greater than or equal to 1928 psig. As described in the Bases for CTS 3.5, IP2 uses the combination of this nominal trip setpoint and an associated 'administrative limit' which is controlled outside of the Technical Specifications to establish trip function Operability. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

ITS 3.3.1, Function 7.a, Pressurizer Pressure-Low, will use the CTS "administrative limit," which is equivalent to the current licensing basis "Allowable Value," (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS). Use of the "Allowable Value," as the LSSS required to be in the Technical Specifications by 10 CFR 50.36(c)(1), is consistent with the guidance provided in Regulatory Guide 1.105, 'Setpoints for Safety-Related Instrumentation.'

In conjunction with the change which will include the allowable value in the ITS, IP2 will elect the option described in STS (NUREG-1431) to maintain the nominal trip setpoint (i.e., as-left limit) in a licensee controlled document. Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.6.

Justification for Change

Using the CTS "administrative limit" (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS) is an administrate change with no impact on safety. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.6.

A.11.f 3.3.1: Reactor Protection System (RPS) Instrumentation

Rev. 7 Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.1, Function 7.b, Pressurizer Pressure-High.

Description of Change

CTS 2.3.1.B (2) establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the Low Pressurizer Pressure function at less than or equal to 2363 psig. As described in the Bases for CTS 3.5, IP2 uses the combination of this nominal trip setpoint and an associated 'administrative limit' which is controlled outside of the Technical Specifications to establish trip function Operability. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

ITS 3.3.1, Function 7.b, Pressurizer Pressure-High, will use the CTS "administrative limit," which is equivalent to the current licensing basis "Allowable Value," (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS). Use of the "Allowable Value," as the LSSS required to be in the Technical Specifications by 10 CFR 50.36(c)(1), is consistent with the guidance provided in Regulatory Guide 1.105, 'Setpoints for Safety-Related Instrumentation.'

In conjunction with the change which will include the allowable value in the ITS, IP2 will elect the option described in STS (NUREG-1431) to maintain the nominal trip setpoint (i.e., as-left limit) in a licensee controlled document. Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.6.

Justification for Change

Using the CTS "administrative limit" (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS) is an administrate change with no impact on safety. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.6.

A.12.f 3.3.1: Reactor Protection System (RPS) Instrumentation

Rev. 7 Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.1, Function 8, Pressurizer Water Level-High.

Description of Change

CTS 2.3.1.C (1) establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the Pressurizer High Water Level function at greater than or equal to 90% of span. As described in the Bases for CTS 3.5, IP2 uses the combination of this nominal trip setpoint and an associated 'administrative limit' which is controlled outside of the Technical Specifications to establish trip function Operability. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

ITS 3.3.1, Function 8, Pressurizer Water Level-High, will use the CTS "administrative limit," which is equivalent to the current licensing basis "Allowable Value," (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS). Use of the "Allowable Value," as the LSSS required to be in the Technical Specifications by 10 CFR 50.36(c)(1), is consistent with the guidance provided in Regulatory Guide 1.105, 'Setpoints for Safety-Related Instrumentation.'

In conjunction with the change which will include the allowable value in the ITS, IP2 will elect the option described in STS (NUREG-1431) to maintain the nominal trip setpoint (i.e., as-left limit) in a licensee controlled document. Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.6.

Justification for Change

Using the CTS "administrative limit" (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS) is an administrate change with no impact on safety. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.6.

A.13.f 3.3.1: Reactor Protection System (RPS) Instrumentation

Rev. 7 Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.1, Function 9, Reactor Coolant Flow-Low.

Description of Change

CTS 2.3.1.B (6) establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the Reactor Coolant Flow-Low function at greater than or equal to 92% of normal indicated loop flow. As described in the Bases for CTS 3.5, IP2 uses the combination of this nominal trip setpoint and an associated 'administrative limit' which is controlled outside of the Technical Specifications to establish trip function Operability. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

ITS 3.3.1, Function 9, Reactor Coolant Flow - Low, will use the CTS "administrative limit," which is equivalent to the current licensing basis "Allowable Value," (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS). Use of the "Allowable Value," as the LSSS required to be in the Technical Specifications by 10 CFR 50.36(c)(1), is consistent with the guidance provided in Regulatory Guide 1.105, 'Setpoints for Safety-Related Instrumentation.'

In conjunction with the change which will include the allowable value in the ITS, IP2 will elect the option described in STS (NUREG-1431) to maintain the nominal trip setpoint (i.e., as-left limit) in a licensee controlled document. Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.6.

Justification for Change

Using the CTS "administrative limit" (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS) is an administrate change with no impact on safety. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.6.

A.16.f 3.3.1: Reactor Protection System (RPS) Instrumentation

Rev. 7 Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.1, Function 11, RCP Undervoltage (6.9 kV bus).

Description of Change

CTS 2.3.1.B (7) establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the RCP Undervoltage (6.9 kV bus) function at greater than or equal to 70% of normal voltage. As described in the Bases for CTS 3.5, IP2 uses the combination of this nominal trip setpoint and an associated 'administrative limit' which is controlled outside of the Technical Specifications to establish trip function Operability. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

ITS 3.3.1, Function 11, RCP Undervoltage (6.9 kV bus), will use the CTS "administrative limit," which is equivalent to the current licensing basis "Allowable Value," (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS). Use of the "Allowable Value," as the LSSS required to be in the Technical Specifications by 10 CFR 50.36(c)(1), is consistent with the guidance provided in Regulatory Guide 1.105, 'Setpoints for Safety-Related Instrumentation.'

In conjunction with the change which will include the allowable value in the ITS, IP2 will elect the option described in STS (NUREG-1431) to maintain the nominal trip setpoint (i.e., as-left limit) in a licensee controlled document. Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.6.

Justification for Change

Using the CTS "administrative limit" (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS) is an administrate change with no impact on safety. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.6.

A.17.f 3.3.1: Reactor Protection System (RPS) Instrumentation

Rev. 7 Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.1, Function 12, RCP Underfrequency (6.9 kV bus).

Description of Change

CTS 2.3.1.B (6) establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the Reactor Coolant Pump low frequency function at greater than or equal to 57.5 cycles per second (i.e., hertz). As described in the Bases for CTS 3.5, IP2 uses the combination of this nominal trip setpoint and an associated 'administrative limit' which is controlled outside of the Technical Specifications to establish trip function Operability. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

ITS 3.3.1, Function 9, Reactor Coolant Flow - Low, will use the CTS "administrative limit," which is equivalent to the current licensing basis "Allowable Value," (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS). Use of the "Allowable Value," as the LSSS required to be in the Technical Specifications by 10 CFR 50.36(c)(1), is consistent with the guidance provided in Regulatory Guide 1.105, 'Setpoints for Safety-Related Instrumentation.'

In conjunction with the change which will include the allowable value in the ITS, IP2 will elect the option described in STS (NUREG-1431) to maintain the nominal trip setpoint (i.e., as-left limit) in a licensee controlled document. Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.6.

Justification for Change

Using the CTS "administrative limit" (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS) is an administrate change with no impact on safety. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.6.

A.18.f 3.3.1: Reactor Protection System (RPS) Instrumentation

Rev. 7 Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.1, Function 13, Steam Generator (SG) Water Level low-low.

Description of Change

CTS 2.3.1.C (2) establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the steam generator water level low-low function at greater than or equal to 7% of the narrow range instrument span. As described in the Bases for CTS 3.5, IP2 uses the combination of this nominal trip setpoint and an associated 'administrative limit' which is controlled outside of the Technical Specifications to establish trip function Operability. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

ITS 3.3.1, Function 13, Steam Generator (SG) Water Level low-low, will use the CTS "administrative limit," which is equivalent to the current licensing basis "Allowable Value," (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS). Use of the "Allowable Value," as the LSSS required to be in the Technical Specifications by 10 CFR 50.36(c)(1), is consistent with the guidance provided in Regulatory Guide 1.105, 'Setpoints for Safety-Related Instrumentation.'

In conjunction with the change which will include the allowable value in the ITS, IP2 will elect the option described in STS (NUREG-1431) to maintain the nominal trip setpoint (i.e., as-left limit) in a licensee controlled document. Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.6.

Justification for Change

Using the CTS "administrative limit" (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS) is an administrate change with no impact on safety. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.6.

A.20.f 3.3.1: Reactor Protection System (RPS) Instrumentation

Rev. 7 Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.1, Function 15, Turbine Trip-Low Auto Stop Oil Pressure.

Description of Change

CTS does not establish any trip setpoint limiting safety system setting (allowable value) for the Turbine Trip-Low Auto Stop Oil Pressure. However, the calibration procedure ensures that the setpoint is below the minimum turbine control oil pressure that will allow the turbine to Operate.

ITS 3.3.1, Function 15, Turbine Trip-Low Auto Stop Oil Pressure, will use the CTS "administrative limit," which is equivalent to the current licensing basis "Allowable Value," (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS). Use of the "Allowable Value," as the LSSS required to be in the Technical Specifications by 10 CFR 50.36(c)(1), is consistent with the guidance provided in Regulatory Guide 1.105, 'Setpoints for Safety-Related Instrumentation.'

In conjunction with the change which will include the allowable value in the ITS, IP2 will elect the option described in STS (NUREG-1431) to maintain the nominal trip setpoint (i.e., as-left limit) in a licensee controlled document. Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.6.

Justification for Change

Using the CTS "administrative limit" (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS) is an administrate change with no impact on safety. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.6.

A.24.f 3.3.1: Reactor Protection System (RPS) Instrumentation

Rev. 7 Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.1, Function 17.c, Power Range Neutron Flux (P-8) Interlock.

Description of Change

ITS 3.3.1, Function 17.c, Power Range Neutron Flux (P-8) Interlock, will use an "Allowable Value" (i.e., as-found setpoint) as the Limiting Safety System Setting. As described in the Bases for CTS 3.5, IP2 uses the combination of this nominal trip setpoint and an associated 'administrative limit' which is controlled outside of the Technical Specifications to establish trip function Operability. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

Justification for Change

Using the CTS "administrative limit" (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS) is an administrate change with no impact on safety. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.6.

A.25.f 3.3.1: Reactor Protection System (RPS) Instrumentation

Rev. 7 Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.1, Function 17.d, Power Range Neutron Flux (P-10) Interlock.

Description of Change

ITS 3.3.1, Function 17.d, Power Range Neutron Flux (P-10) Interlock, will use an "Allowable Value" (i.e., as-found setpoint) as the Limiting Safety System Setting. As described in the Bases for CTS 3.5, IP2 uses the combination of this nominal trip setpoint and an associated 'administrative limit' which is controlled outside of the Technical Specifications to establish trip function Operability. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

Justification for Change

Using the CTS "administrative limit" (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS) is an administrate change with no impact on safety. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.6.

A.26.f 3.3.1: Reactor Protection System (RPS) Instrumentation

Rev. 7 Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.1, Function 17.e, Turbine First Stage Pressure (P-7 Input) Interlock.

Description of Change

TS 3.3.1, Function 17.e, Turbine First Stage Pressure (P-7 Input) Interlock, will use an "Allowable Value" (i.e., as-found setpoint) as the Limiting Safety System Setting. As described in the Bases for CTS 3.5, IP2 uses the combination of this nominal trip setpoint and an associated 'administrative limit' which is controlled outside of the Technical Specifications to establish trip function Operability. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

CTS 2.3.2.A.(2) specifies that Turbine First Stage Pressure (P-7 Input) interlock must enable the reactor trips on low pressurizer pressure, high pressurizer level, and low reactor coolant flow for two or more loops when Turbine first stage pressure >10% "of equivalent full load." Turbine First Stage Pressure (P-7 Input) function takes advantage of the fact that turbine first stage pressure tracks total turbine power output very closely. Unless steam is being dumped (e.g., SG safety valves, atmospheric dump valves, turbine bypass to the condenser), turbine power is an excellent proxy for reactor thermal power. Note, however, that Turbine First Stage Pressure (P-7 Input) is only one of two interlocks that enable the reactor protection system trips listed above at approximately 10% reactor power. The other interlock, P-10 which is also an input to P-7, uses power range neutron flux as the basis for enabling the reactor protection system trips listed above are enabled at approximately 10% reactor power.

ITS 3.3.1, Function 17.e, Turbine First Stage Pressure (P-7 Input), maintains the requirement in CTS 2.3.2.A.(2); however, ITS 3.3.1, Function 17.e, expresses the allowable value for this interlock as percent "turbine power" versus the use of percent "equivalent full load."

The combination of the function name, Turbine First Stage Pressure (P-7 Input), and the description "turbine power" or "equivalent full load" clear explain that allowable value must be established as a proxy for reactor thermal power and the descriptive terms are interchangeable.

ITS 3.3.1, Function 17.e, Turbine First Stage Pressure (P-7 Input), will use the CTS "administrative limit," which is equivalent to the current licensing basis "Allowable Value," (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS). Use of the "Allowable Value," as the LSSS required to be in the Technical Specifications by 10 CFR 50.36(c)(1), is consistent with the guidance provided in Regulatory Guide 1.105, 'Setpoints for Safety-Related Instrumentation.'

In conjunction with the change which will include the allowable value in the ITS, IP2 will elect the option described in STS (NUREG-1431) to maintain the nominal trip setpoint (i.e., as-left limit) in a licensee controlled document. Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.6.

Justification for Change

Using the CTS "administrative limit" (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS) is an administrate change with no impact on safety. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable

value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.6.

L.01 Rev. 7

3.3.1: Reactor Protection System (RPS) Instrumentation

Category Less Restrictive (Cat V): Relaxation of LCO Requirement

DOC Summary:

Not Used.

Description of Change

Not Used.

Justification for Change

Not Used.

LA.6 Rev. 7

3.3.1: Reactor Protection System (RPS) Instrumentation

Category Relocated Detail (Type 3): Relocates Procedural Details for Meeting TS Requirements and

DOC Summary:

Relocates the CTS nominal trip setpoints (i.e., as-left limits) to plant procedures because IP2 ITS will use the "Allowable Value" instead of the nominal trip setpoint as the limiting safety system setting (LSSS) that is required to be in the Technical Specifications by 10 CFR 50.36(c)(1).

Description of Change

IP2 CTS uses the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting (LSSS) that is required to be in the Technical Specifications by 10 CFR 50.36(c)(1) for the Reactor Protection System, Engineered Safety Feature Actuation System, and Loss of Power (LOP) Diesel Generator Start Instrumentation.

IP2 ITS LCO 3.3.1, RPS Instrumentation, LCO 3.3.2, ESFAS Instrumentation, and LCO 3.3.5, LOP DG Start Instrumentation, will use the "Allowable Value," as the LSSS required to be in the Technical Specifications by 10 CFR 50.36(c)(1). Using the "Allowable Value" as the LSSS is consistent with the guidance provided in Regulatory Guide 1.105, 'Setpoints for Safety-Related Instrumentation,' and STS (NUREG-1431).

In conjunction with the change, IP2 will elect the option described in STS (NUREG-1431) to maintain the nominal trip setpoint (i.e., as-left limit) in a licensee controlled document. Relocation of the nominal trip setpoint currently in the CTS to plant procedures is a less restrictive administrative change.

Justification for Change

This change is acceptable because IP2 ITS will use the "Allowable Value" instead of the nominal trip setpoint as the limiting safety system setting (LSSS) that is required to be in the Technical Specifications by 10 CFR 50.36(c)(1). Using the "Allowable Value" instead of the nominal trip setpoint as the LSSS is consistent with the guidance provided in Regulatory Guide 1.105, 'Setpoints for Safety-Related Instrumentation,' and STS (NUREG-1431).

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
	G.2.1 Be in MODE 3. AND G.2.2 Be in MODE 4.	30 hours 36 hours
H. Main Boiler Feedwater Pump trip channel(s) inoperable.	H.1 Verify one channel associated with an operating MBFP is OPERABLE. AND H.2 Restore one channel associated with each operating MBFP to OPERABLE status.	Immediately 48 hours
I. Required Action and associated Completion Time of Condition H not met.	I.1 Be in MODE 3.	6 hours
J. One or more channels inoperable.	J.1 Verify interlock is in required state for existing unit condition. OR J.2.1 Be in MODE 3. AND J.2.2 Be in MODE 4.	1 hour 7 hours 13 hours

Table 3.3.2-1 (page 4 of 4)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
5. Feedwater Isolation					
a. Automatic Actuation Logic and Actuation Relays	1, 2[(d)], 3[(d)]	2 trains	G	SR 3.3.2.2 SR 3.3.2.3 SR 3.3.2.5	NA
b. SG Water Level - High High	1, 2[(d)], 3[(d)]	3 per SG	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≤ 77.7% NR
c. Safety Injection	[(d)] Refer to Function 1 (Safety Injection) for all initiation functions and requirements.				
6. Auxiliary Feedwater					
a. Automatic Actuation Logic and Actuation Relays	1,2,3	2 trains	G	SR 3.3.2.2 SR 3.3.2.3 SR 3.3.2.5	NA
b. SG Water Level - Low Low	1,2,3	3 per SG	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≥ 3.7% NR
c. Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.				
d. Station Blackout (SBO) (Undervoltage Bus 5A or 6A)	1,2,3	Refer to LCO 3.3.5, "LOP DG Start Instrumentation," for requirements.			
e. Trip of Main Boiler Feedwater Pump	1[(e)], 2[(e)]	1 per MBFP	H	SR 3.3.2.6 SR 3.3.2.7	≥ 19.5 psig
7. ESFAS Interlocks Pressurizer Pressure	1,2,3	3	J	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≤ 1980 psig

(d) Except when the main feedwater flowpath to each SG is isolated by a closed and deactivated automatic valve or a closed manual valve.

(e) Only required for MBFPs that are in operation.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

steam line breaks (SLBs) outside containment. Functions such as manual initiation, not specifically credited in the accident safety analysis, are qualitatively credited in the safety analysis and the NRC staff approved licensing basis for the unit. These Functions may provide protection for conditions that do not require dynamic transient analysis to demonstrate Function performance. These Functions may also serve as backups to Functions that were credited in the accident analysis (Ref. 3).

The LCO requires all instrumentation performing an ESFAS Function identified in Table 3.3.2-1 to be OPERABLE. A channel is OPERABLE with a trip setpoint value outside its calibration tolerance band provided the trip setpoint "as-found" value does not exceed its associated Allowable Value and provided the trip setpoint "as-left" value is adjusted to a value within the calibration tolerance band of the Nominal Trip Setpoint. A trip setpoint may be set more conservative than the Nominal Trip Setpoint as necessary in response to plant conditions. Failure of any instrument renders the affected channel(s) inoperable and reduces the reliability of the affected Functions.

The LCO generally requires OPERABILITY of four or three channels in each instrumentation function and two channels in each logic and manual initiation function. The two-out-of-three and the two-out-of-four configurations allow one channel to be tripped during maintenance or testing without causing an ESFAS initiation. Two logic or manual initiation channels are required to ensure no single random failure disables the ESFAS.

The required channels of ESFAS instrumentation provide unit protection in the event of any of the analyzed accidents. ESFAS protection functions are as follows:

1. <u>Safety Injection</u>

   Safety Injection (SI) provides two primary functions necessary to mitigate the effects of high energy line breaks (HELBs) both inside and outside of containment:

   1. Primary side water addition to ensure maintenance or recovery of reactor vessel water level (coverage of the active fuel for heat removal, clad integrity, and for limiting peak clad temperature to < 2200°F), and

   2. Boration to ensure recovery and maintenance of SDM (k_{eff} < 1.0).

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

2. Containment Spray

Containment Spray provides two primary functions:

1. Lowers containment pressure and temperature after a HELB in containment, and

2. Reduces the amount of radioactive iodine in the containment atmosphere.

These functions are necessary to:

- Ensure the pressure boundary integrity of the containment structure, and

- Limit the release of radioactive iodine to the environment in the event of a failure of the containment structure.

The containment spray actuation signal starts the containment spray pump associated with that logic train and aligns the discharge of the pumps to the containment spray nozzle headers in the upper levels of containment. Water is initially drawn from the RWST by the containment spray pumps. When the RWST reaches a specified minimum level, the spray pumps are manually secured. Recirculation or RHR pumps are used by diverting flow to the spray headers if continued containment spray is required. Containment spray is actuated manually or by Containment Pressure - High High.

a. Containment Spray - Manual Initiation

The operator can initiate containment spray at any time from the control room. Manual initiation of containment spray (CS) requires that either of two pushbuttons in the control room be depressed. Each pushbutton will actuate one logic train and the associated CS train. Two trains are required to be Operable (one pushbutton associated with each logic train).

Note that Manual Initiation of containment spray also actuates Phase B containment isolation and containment purge and exhaust line isolation and pressure relief line isolation.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Spray. When the two CS pushbuttons are depressed simultaneously, Phase B Containment Isolation and Containment Spray will be actuated in both trains.

a. Containment Isolation - Phase A Isolation

(1) Phase A Isolation - Manual Initiation

Manual Phase A Containment Isolation is actuated by either of two pushbuttons in the control room. Each pushbutton actuates one logic train. Note that manual initiation of Phase A Containment Isolation also actuates isolation of Containment Purge and Exhaust and the Containment Pressure relief line.

(2) Phase A Isolation - Automatic Actuation Logic and Actuation Relays

Automatic Actuation Logic and Actuation Relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

Manual and automatic initiation of Phase A Containment Isolation must be OPERABLE in MODES 1, 2, and 3, when there is a potential for an accident to occur. Manual initiation is also required in MODE 4 even though automatic actuation is not required. In this MODE, adequate time is available to manually actuate required components in the event of a DBA, but because of the large number of components actuated on a Phase A Containment Isolation, actuation is simplified by the use of the manual actuation pushbuttons. Automatic actuation logic and actuation relays must be OPERABLE in MODE 4 to support system level manual initiation. In MODES 5 and 6, there is insufficient energy in the primary or secondary systems to pressurize the containment to require Phase A Containment Isolation. There also is adequate time for the operator to evaluate unit conditions and manually actuate individual isolation valves in response to abnormal or accident conditions.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Feedwater Isolation Functions must be OPERABLE in MODES 1, 2 and 3 except when the main feedwater flowpath to each SG is isolated by a closed and deactivated automatic valve or a closed manual valve when the MFW System is in operation and the turbine generator may be in operation. In MODES 4, 5, and 6, the MFW System is not in service and this Function is not required to be OPERABLE.

6. Auxiliary Feedwater

The AFW System is designed to provide a secondary side heat sink for the reactor in the event that the MFW System is not available. The system has two motor driven pumps and a turbine driven pump. This ensures AFW is available during normal unit operation, during a loss of AC power and a loss of MFW. The normal source of water for the AFW System is the condensate storage tank (CST). The AFW System is aligned so that upon a motor driven pump start, flow is initiated to the respective SGs immediately.

a. Auxiliary Feedwater - Automatic Actuation Logic and Actuation Relays

Automatic actuation logic and actuation relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

b. Auxiliary Feedwater - Steam Generator Water Level - Low Low

SG Water Level - Low Low provides protection against a loss of heat sink. A feed line break, inside or outside of containment, or a loss of MFW, would result in a loss of SG water level. Signals from two-out-of-three channels from any one SG will start the motor driven AFW pumps. Signals from two-out-of-three channels from any two SGs will start the steam driven AFW pump. The LCO requires three OPERABLE channels per steam generator.

With the transmitters (d/p cells) located inside containment and thus possibly experiencing adverse environmental conditions (feed line break), the Allowable Value reflects the inclusion of both steady state and adverse environmental instrument uncertainties.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

c. Auxiliary Feedwater - Safety Injection

An SI signal starts the motor driven AFW pumps. The AFW initiation functions are the same as the requirements for their SI function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 1, SI, is referenced for all initiating functions and requirements.

d. Auxiliary Feedwater – Station Blackout (SBO) (Undervoltage Bus 5A or 6A)

The SBO Function that generates Auxiliary Feedwater system start signals uses the same undervoltage relays (i.e., channels) required to be OPERABLE by LCO 3.3.5, "Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation," Function c. In addition to the DG starting function described in the Bases of LCO 3.3.5, the SBO Function generates an automatic start signal for the turbine driven AFW pump if the undervoltage condition occurs in conjunction with a unit trip if no ESFAS safety injection signal is present. The SBO Function also generates an automatic start signal for the motor driven AFW pumps if the undervoltage condition occurs in conjunction with a unit trip.

As described in the Bases of LCO 3.3.5, the SBO relays (i.e., channels) consist of two sets of three relays with one set of three relays associated with 480 V safeguards bus 5A (SBO train 5A) and the other set of three relays associated with safeguards bus 6A (SBO train 6A). If there is a loss of voltage on 480 V bus 5A or 6A, two out of the three SBO undervoltage relays associated with either bus 5A or 6A will actuate the undervoltage portion of the SBO function.

LCO 3.3.2, Function 6.d, Auxiliary Feedwater SBO (Undervoltage Bus 5A or 6A), establishes requirements (except for the applicability) for the SBO start of the auxiliary feedwater pumps by referencing the SBO requirements in LCO 3.3.5, Function c. This is acceptable because the requirements for the SBO function for the number of OPERABLE channels, the Required Actions when one or more channels are inoperable, Surveillance Testing of SBO channels, and the allowable values for LCO 3.3.2, Function 6.d, and LCO 3.3.5, Function c.1, are identical. However, LCO 3.3.5, Function c.1, LOP DG Start Instrumentation, is applicable in MODES 1, 2, 3 and 4 and LCO 3.3.2, Function 6.d, Auxiliary Feedwater SBO, is only

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

applicable in MODES 1, 2, and 3. Therefore, if the requirements of LCO 3.3.5, Function c.1, LOP DG Start Instrumentation, are met, then the LCO 3.3.2, Function 6.d, Auxiliary Feedwater SBO (Undervoltage Bus 5A or 6A), are also met.

LCO 3.3.2, Function 6.a, Auxiliary Feedwater - Automatic Actuation Logic and Actuation Relays, and LCO 3.7.5, Auxiliary Feedwater (AFW) System, establish Required Actions and Surveillance Testing for the logic that changes the function of the SBO relays depending on the presence of a safety injection signal and unit trip signal.

This function is needed because loss of offsite power to the 6.9 kV buses (and consequently the 480 V buses) will be accompanied by a loss of reactor coolant pumping power and the subsequent need for some method of decay heat removal.

Functions 6.a through 6.d must be OPERABLE in MODES 1, 2, and 3 to ensure that the SGs remain the heat sink for the reactor. SG Water Level - Low Low in any operating SG will cause the motor driven AFW pumps to start. The system is aligned so that upon a start of the pump, water immediately begins to flow to the SGs. SG Water Level - Low Low in any two operating SGs will cause the turbine driven pumps to start. These Functions do not have to be OPERABLE in MODES 5 and 6 because there is not enough heat being generated in the reactor to require the SGs as a heat sink. In MODE 4, AFW actuation does not need to be OPERABLE because either AFW or residual heat removal (RHR) will already be in operation to remove decay heat or sufficient time is available to manually place either system in operation.

e. <u>Auxiliary Feedwater - Trip of Main Boiler Feedwater Pump</u>

A Trip of either MBFP is an indication of a potential loss of MFW and the subsequent potential need for some method of decay heat and sensible heat removal to bring the reactor back to no load temperature and pressure. Each turbine driven MBFP is equipped with a pressure switch on the control oil line for the speed control system. A low pressure signal from this pressure switch indicates a trip of that pump. The single channel associated with each operating MBFP will start both motor driven AFW pumps. However, there is no single failure tolerance for this Function unless both MBFPs are operating. This is

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ACTIONS (continued)

The single channel associated with each operating MBFP will start both motor driven AFW pumps if either MBFP trips. This ensures that AFW is started on a loss of main feedwater. However, there is no single failure tolerance for this Function unless both MBFPs are operating. Therefore, when a channel is inoperable, Required Action H.1 requires immediate verification that a channel associated with an operating MBFP is OPERABLE to ensure that AFW will start automatically when there is a loss of main feedwater. Otherwise, Required Action I.1 requires that the plant be in MODE 3 within the following 6 hours. The requirement for verification of the status of the channel associated with an operating MBFP may be completed by an administrative review. Actual testing is not required.

If both MBFPs are operating and there is an OPERABLE channel associated with only one operating pump, Required Action H.2 allows 48 hours to restore redundancy by requiring an OPERABLE channel for each operating MBFP. Otherwise, Required Action I.1 requires that the plant be in MODE 3 within the following 6 hours. Operating without redundant channels when only one MBFP is operating and operating for 48 hours when only one of the two MBFPs has an OPERABLE AFW starting channel is acceptable because this Function is a backup method for starting AFW and other Functions, in particular SG Water Level - Low Low, provide the primary protection against a loss of heat sink.

The Required Action I.1 Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging unit systems. In MODE 3, the unit does not have any analyzed transients or conditions that require the explicit use of the protection function noted above.

J.1, J.2.1 and J.2.2

Condition J applies to the Pressurizer Pressure interlock.

With one or more channels inoperable, the operator must verify that the interlock is in the required state for the existing unit condition. This action manually accomplishes the function of the interlock. Determination must be made within 1 hour. The 1 hour Completion Time is equal to the time allowed by LCO 3.0.3 to initiate shutdown actions in the event of a complete loss of ESFAS function. If the interlock is not in the required state (or placed in the required state) for the existing unit condition, the unit must be placed in MODE 3 within the next 6 hours and MODE 4 within the following 6 hours. The allowed Completion Times are reasonable, based on operating

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.2

SR 3.3.2.2 is the performance of an ACTUATION LOGIC TEST. The relay logic is tested every 92 days on a STAGGERED TEST BASIS. The train being tested is placed in the bypass condition, thus preventing inadvertent actuation. All possible logic combinations, with and without applicable permissives, are tested for each protection function. In addition, the master relay is tested. This verifies that the logic modules are OPERABLE and that there is a voltage signal path to the master relay coils. The Frequency of every 92 days on a STAGGERED TEST BASIS is justified in Reference 10.

SR 3.3.2.3

SR 3.3.2.3 is the performance of a MASTER RELAY TEST. The MASTER RELAY TEST is the energizing of the master relay, verifying contact operation and a low voltage continuity check of the slave relay coil. Upon master relay contact operation, a low voltage is supplied to the slave relay coil. This voltage is insufficient to pick up the slave relay, but large enough to demonstrate signal path continuity. This test is performed every 31 days on a STAGGERED TEST BASIS. The time allowed for the testing (8 hours) and the surveillance interval are justified in Reference 7.

SR 3.3.2.4

SR 3.3.2.4 is the performance of a COT. A COT is performed on each required channel to ensure the entire channel (except for the transmitter sensing device) will perform the intended Function. Setpoints must be found within calibration acceptance criteria consistent with the Allowable Values specified in Table 3.3.2-1. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL OPERATIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

The "as found" and "as left" values must also be recorded and reviewed for consistency with the assumptions of Reference 6 which incorporates the assumptions of Reference 7. The difference between the current "as found" values and the previous test "as left" values must be consistent with the drift allowance used in the setpoint methodology. The setpoint shall be left set consistent with the assumptions of the current unit specific setpoint methodology.

Add ITS 3.3.2, Function 5.b, SG Level- High High A.25 - M.8

Table 3.5-1

Engineered Safety Features Initiation Instrument Setting Limits

	No.	Functional Unit	Channel	Setting Limits	
T3.3.2-1, #1.c	1.	High Containment Pressure (Hi Level)	Safety Injection	LA.4 ≤ 2.0 psig 8.6 A.5.f	A.5
T3.3.2-1, #2.e 4.e 3.b.(3)	2.	High Containment Pressure (Hi-Hi Level)	a. Containment Spray b. Steam Line Isolation	LA.4 ≤ 24 psig 28.6 A.12.f A.18.f A.21.f	A.12 A.21 A.18
T3.3.2-1, #1d	3.	Pressurizer Low Pressure	Safety Injection	LA.4 ≥ 1833 psig 1801 A.6.f	A.6
T3.3.2-1, #1.e	4.	High Differential Pressure Between Steam Lines	Safety Injection	LA.4 ≤ 155 psi 237.6 psid A.7.f	A.7
T3.3.2-1, #1.f 1.g T3.3.2-1, #4.d 4.e	5.	High Steam Flow in 2/4 Steam Lines Coincident with Low Tavg or Low Steam Line Pressure	a. Safety Injection b. Steam Line Isolation A.8.f A.9.f A.22.f A.23.f 53.7 1108 A.8.f A.22.f 540.75 A.9.f A.23.f 425.0	≤ 40% of full steam flow at zero load ≤ 40% of full steam flow at 20% load ≤ 110% of full steam flow at full load LA.4 ≥ 540°F T_{avg} LA.4 ≥ 525 psig steam line pressure	A.8 A.9 A.22 A.23
T3.3.2-1, #6.b	6.	Steam Generator Water Level (Low-Low)	Auxiliary Feedwater A.28.f 3.7	≥ 7% of narrow range instrument span each steam generator LA.4	A.28
T3.3.2-1, #6.d	7.	Station Blackout (Undervoltage)	Auxiliary Feedwater A.30.f 198.6V	≥ 40% nominal voltage LA.4	A.30
SEE ITS 3.3.5	8a.	480V Emergency Bus Undervoltage (Loss of Voltage)	------	220V + 100V, -20V 3 sec ± 1 sec	
	8b.	480V Emergency Bus Undervoltage (Degraded Voltage)	------	421V ± 6V 180 sec ± 30 sec (no SI) 10 sec ± 2 sec (coincident	

Table 4.1-1

Minimum Frequencies for Checks, Calibrations and Tests of Instrument Channels

	Channel Description	Check	Calibrate	Test	Remarks	
SEE ITS 3.3.1	8.a 6.9 kV Voltage	N.A.	R#	Q		
	8.b 6.9 kV Frequency	N.A.	R#	Q (1) R# (2)	1) Underfrequency relay actuation only. 2) The full test including RCP breaker trip upon underfrequency relay actuation and reactor trip logic relay actuation upon tripping of the RCP breaker.	
SEE ITS 3.1.4, 3.1.5, 3.1.7	9. Analog Rod Position	S	R#	M		
	10. Rod Position Bank Counters	S	N.A.	N.A.	With analog rod position	
T 3.3.2-1, #5.b	11. Steam Generator Level	12 hr. S SR 3.3.2.1	24 Month R# SR 3.3.2.7	184 days Q SR 3.3.2.4	L.6	A.25 A.28
SEE CTS RELOCATED	12. Charging Flow	N.A.	R#	N.A.		
	13. Residual Heat Removal Pump Flow	N.A.	R#	N.A.		
	14. Boric Acid Tank Level	W	R#	N.A.		
SEE ITS 3.5.4	15. Refueling Water Storage Tank Level	W	Q	N.A.		
	16. DELETED					
SEE RELOC. R.2	17. Volume Control Tank Level	N.A.	R##	N.A.		
	18a. Containment Pressure M.6	~~S~~	24 Month R# A.38	184 days Q L.6	Wide Range	A.12 A.18 A.21
T 3.3.2-1 #1.c	18b. Containment Pressure	S SR 3.3.2.1	R# SR 3.3.2.7	~~Q~~ SR 3.3.2.4 184 L.6	Narrow Range	A.5

ITS Package Revision -1-

T3.3.2-1, #2.c
#3.b(3)
#4.c

ITS 3.3.2

Discussions of Changes:

A.05.f <u>3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation</u>

Rev. 7 <u>Category</u> Administrative: No Technical Changes

<u>DOC Summary:</u>

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.2, Function 1.c, Safety Injection-Containment Pressure-High.

<u>Description of Change</u>

CTS Table 3.5-1, Function 1, establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the Containment Pressure-High function at less than or equal to 2.0 psig. As described in the Bases for CTS 3.5, IP2 uses the combination of this nominal trip setpoint and an associated 'administrative limit' which is controlled outside of the Technical Specifications to establish trip function Operability. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

ITS 3.3.2, Function 1.c, Safety Injection-Containment Pressure-High, will use the CTS "administrative limit," which is equivalent to the current licensing basis "Allowable Value," (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS). Use of the "Allowable Value;" as the LSSS required to be in the Technical Specifications by 10 CFR 50.36(c)(1), is consistent with the guidance provided in Regulatory Guide 1.105, 'Setpoints for Safety-Related Instrumentation.'

In conjunction with the change which will include the allowable value in the ITS, IP2 will elect the option described in STS (NUREG-1431) to maintain the nominal trip setpoint (i.e., as-left limit) in a licensee controlled document. Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.4.

<u>Justification for Change</u>

Using the CTS "administrative limit" (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS) is an administrate change with no impact on safety. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.4.

A.06.f 3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation

Rev. 7 Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.2, Function 1.d, Safety Injection - Pressurizer Pressure - Low

Description of Change

CTS Table 3.5-1, Function 3, Pressurizer Pressure Low, establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the Pressurizer Pressure - Low function at greater than or equal to 1833 psig. As described in the Bases for CTS 3.5, IP2 uses the combination of this nominal trip setpoint and an associated 'administrative limit' which is controlled outside of the Technical Specifications to establish trip function Operability. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

ITS 3.3.2, Function 1.d, Safety Injection - Pressurizer Pressure - Low, will use the CTS "administrative limit," which is equivalent to the current licensing basis "Allowable Value," (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS). Use of the "Allowable Value," as the LSSS required to be in the Technical Specifications by 10 CFR 50.36(c)(1), is consistent with the guidance provided in Regulatory Guide 1.105, 'Setpoints for Safety-Related Instrumentation.'

In conjunction with the change which will include the allowable value in the ITS, IP2 will elect the option described in STS (NUREG-1431) to maintain the nominal trip setpoint (i.e., as-left limit) in a licensee controlled document. Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.4.

Justification for Change

Using the CTS "administrative limit" (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS) is an administrate change with no impact on safety. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.4.

A.07.f 3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation

Rev. 7 Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.2, Function 1.e. Safety Injection-High Differential Pressure Between Steam Lines

Description of Change

CTS Table 3.5-1, Function 4, High Differential Pressure Between Steam Lines, establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the High Differential Pressure Between Steam Lines function at less than or equal to 155 psi (i.e., psid). As described in the Bases for CTS 3.5, IP2 uses the combination of this nominal trip setpoint and an associated 'administrative limit' which is controlled outside of the Technical Specifications to establish trip function Operability. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

ITS 3.3.2, Function 1.e. Safety Injection-High Differential Pressure Between Steam Lines, will use the CTS "administrative limit," which is equivalent to the current licensing basis "Allowable Value," (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS). Use of the "Allowable Value," as the LSSS required to be in the Technical Specifications by 10 CFR 50.36(c)(1), is consistent with the guidance provided in Regulatory Guide 1.105, 'Setpoints for Safety-Related Instrumentation.'

In conjunction with the change which will include the allowable value in the ITS, IP2 will elect the option described in STS (NUREG-1431) to maintain the nominal trip setpoint (i.e., as-left limit) in a licensee controlled document. Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.4.

Justification for Change

Using the CTS "administrative limit" (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS) is an administrate change with no impact on safety. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.4.

A.08.f 3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation

Rev. 7 Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.2, Function 1.f. Safety Injection - High Steam Flow in Two Steam Lines Coincident with Tave - Low

Description of Change

CTS Table 3.5-1, Item 5, Safety High Steam Flow in 2/4 Steam Lines Coincident with Low Tave or Low Steam Line Pressure, establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the High Steam Flow Coincident with Low Tave or Low Steam Line Pressure function. This setpoint changes based on input from the turbine first stage pressure. As described in the Bases for CTS 3.5, IP2 uses the combination of this nominal trip setpoint and an associated 'administrative limit' which is controlled outside of the Technical Specifications to establish trip function Operability. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

ITS 3.3.2, Functions 1.d, 1.e, 1.f, 4.d and 4.e, will use the CTS "administrative limit," which is equivalent to the current licensing basis "Allowable Value," (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS). Use of the "Allowable Value," as the LSSS required to be in the Technical Specifications by 10 CFR 50.36(c)(1), is consistent with the guidance provided in Regulatory Guide 1.105, 'Setpoints for Safety-Related Instrumentation.'

In conjunction with the change which will include the allowable value in the ITS, IP2 will elect the option described in STS (NUREG-1431) to maintain the nominal trip setpoint (i.e., as-left limit) in a licensee controlled document. Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.4.

Justification for Change

Using the CTS "administrative limit" (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS) is an administrate change with no impact on safety. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.4.

A.09.f 3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation

Rev. 7 **Category** Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.2, Function 1.g. Safety Injection - High Steam Flow in Two Steam Lines Coincident with Steam Line Pressure - Low

Description of Change

CTS Table 3.5-1, Item 5, Safety High Steam Flow in 2/4 Steam Lines Coincident with Low Tave or Low Steam Line Pressure, establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the High Steam Flow Coincident with Low Tave or Low Steam Line Pressure function. This setpoint changes based on input form the turbine first stage pressure. As described in the Bases for CTS 3.5, IP2 uses the combination of this nominal trip setpoint and an associated 'administrative limit' which is controlled outside of the Technical Specifications to establish trip function Operability. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

ITS 3.3.2, Functions 1.d, 1.e, 1.g, 4.d and 4.e, will use the CTS "administrative limit," which is equivalent to the current licensing basis "Allowable Value," (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS). Use of the "Allowable Value," as the LSSS required to be in the Technical Specifications by 10 CFR 50.36(c)(1), is consistent with the guidance provided in Regulatory Guide 1.105, 'Setpoints for Safety-Related Instrumentation.'

In conjunction with the change which will include the allowable value in the ITS, IP2 will elect the option described in STS (NUREG-1431) to maintain the nominal trip setpoint (i.e., as-left limit) in a licensee controlled document. Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.4.

Justification for Change

Using the CTS "administrative limit" (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS) is an administrate change with no impact on safety. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.4.

A.12.f 3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation

Rev. 7 Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.2, Function 2.c, Containment Spray - Containment Pressure (High-High)

Description of Change

CTS Table 3.5-1, Item 2, High Containment Pressure (Hi Hi Level), establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the Containment Pressure (High-High) function at less than or equal to 24 psig. As described in the Bases for CTS 3.5, IP2 uses the combination of this nominal trip setpoint and an associated 'administrative limit' which is controlled outside of the Technical Specifications to establish trip function Operability. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

ITS 3.3.2, Function 2.c, Containment Spray - Containment Pressure (High-High), will use the CTS "administrative limit," which is equivalent to the current licensing basis "Allowable Value," (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS). Use of the "Allowable Value," as the LSSS required to be in the Technical Specifications by 10 CFR 50.36(c)(1), is consistent with the guidance provided in Regulatory Guide 1.105, 'Setpoints for Safety-Related Instrumentation.'

In conjunction with the change which will include the allowable value in the ITS, IP2 will elect the option described in STS (NUREG-1431) to maintain the nominal trip setpoint (i.e., as-left limit) in a licensee controlled document. Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.4.

Justification for Change

Using the CTS "administrative limit" (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS) is an administrate change with no impact on safety. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.4.

A.18.f 3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation

Rev. 7 Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.2, Function 3.b.(3), Containment Phase B Isolation-Containment Pressure (High-High)

Description of Change

CTS Table 3.5-1, Item 2, High Containment Pressure (Hi Hi Level), establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the Containment Pressure (High-High) function at less than or equal to 24 psig. As described in the Bases for CTS 3.5, IP2 uses the combination of this nominal trip setpoint and an associated 'administrative limit' which is controlled outside of the Technical Specifications to establish trip function Operability. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

ITS 3.3.2, Function 3.b.(3), Containment Phase B Isolation-Containment Pressure (High-High), will use the CTS "administrative limit," which is equivalent to the current licensing basis "Allowable Value," (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS). Use of the "Allowable Value," as the LSSS required to be in the Technical Specifications by 10 CFR 50.36(c)(1), is consistent with the guidance provided in Regulatory Guide 1.105, 'Setpoints for Safety-Related Instrumentation.'

In conjunction with the change which will include the allowable value in the ITS, IP2 will elect the option described in STS (NUREG-1431) to maintain the nominal trip setpoint (i.e., as-left limit) in a licensee controlled document. Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.4.

Justification for Change

Using the CTS "administrative limit" (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS) is an administrate change with no impact on safety. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.4.

A.21.f 3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation

Rev. 7 Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.2, Function 4.c, Steam Line Isolation - Containment Pressure (High-High)

Description of Change

CTS Table 3.5-1, Item 2, High Containment Pressure (Hi Hi Level), establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the Containment Pressure (High-High) function at less than or equal to 24 psig. As described in the Bases for CTS 3.5, IP2 uses the combination of this nominal trip setpoint and an associated 'administrative limit' which is controlled outside of the Technical Specifications to establish trip function Operability. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

ITS 3.3.2, Function 4.c, Steam Line Isolation - Containment Pressure (High-High), will use the CTS "administrative limit," which is equivalent to the current licensing basis "Allowable Value," (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS). Use of the "Allowable Value," as the LSSS required to be in the Technical Specifications by 10 CFR 50.36(c)(1), is consistent with the guidance provided in Regulatory Guide 1.105, 'Setpoints for Safety-Related Instrumentation.'

In conjunction with the change which will include the allowable value in the ITS, IP2 will elect the option described in STS (NUREG-1431) to maintain the nominal trip setpoint (i.e., as-left limit) in a licensee controlled document. Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.4.

Justification for Change

Using the CTS "administrative limit" (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS) is an administrate change with no impact on safety. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.4.

A.22.f 3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation

Rev. 7 Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.2, Function 4.d. Steam Line Isolation - High Steam Flow in Two Steam Lines Coincident with Tave - Low

Description of Change

CTS Table 3.5-1, Item 5, Safety High Steam Flow in 2/4 Steam Lines Coincident with Low Tave or Low Steam Line Pressure, establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the High Steam Flow Coincident with Low Tave or Low Steam Line Pressure function. This setpoint changes based on input form the turbine first stage pressure. As described in the Bases for CTS 3.5, IP2 uses the combination of this nominal trip setpoint and an associated 'administrative limit' which is controlled outside of the Technical Specifications to establish trip function Operability. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

ITS 3.3.2, Functions 1.d, 1.e, 4.d and 4.e, will use the CTS "administrative limit," which is equivalent to the current licensing basis "Allowable Value," (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS). Use of the "Allowable Value," as the LSSS required to be in the Technical Specifications by 10 CFR 50.36(c)(1), is consistent with the guidance provided in Regulatory Guide 1.105, 'Setpoints for Safety-Related Instrumentation.'

In conjunction with the change which will include the allowable value in the ITS, IP2 will elect the option described in STS (NUREG-1431) to maintain the nominal trip setpoint (i.e., as-left limit) in a licensee controlled document. Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.4.

Justification for Change

Using the CTS "administrative limit" (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS) is an administrate change with no impact on safety. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.4.

A.23.f 3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation

Rev. 7 Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.2, Function 4.e. Steam Line Isolation - High Steam Flow in Two Steam Lines Coincident with Steam Line Pressure - Low

Description of Change

CTS Table 3.5-1, Item 5, Safety High Steam Flow in 2/4 Steam Lines Coincident with Low Tave or Low Steam Line Pressure, establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the High Steam Flow Coincident with Low Tave or Low Steam Line Pressure function. This setpoint changes based on input form the turbine first stage pressure. As described in the Bases for CTS 3.5, IP2 uses the combination of this nominal trip setpoint and an associated 'administrative limit' which is controlled outside of the Technical Specifications to establish trip function Operability. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

ITS 3.3.2, Functions 1.d, 1.e, 4.d and 4.e, will use the CTS "administrative limit," which is equivalent to the current licensing basis "Allowable Value," (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS). Use of the "Allowable Value," as the LSSS required to be in the Technical Specifications by 10 CFR 50.36(c)(1), is consistent with the guidance provided in Regulatory Guide 1.105, 'Setpoints for Safety-Related Instrumentation.'

In conjunction with the change which will include the allowable value in the ITS, IP2 will elect the option described in STS (NUREG-1431) to maintain the nominal trip setpoint (i.e., as-left limit) in a licensee controlled document. Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.4.

Justification for Change

Using the CTS "administrative limit" (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS) is an administrate change with no impact on safety. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.4.

A.25.f 3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation

Rev. 7 Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.2, Function 5.b, Feedwater Isolation - SG Level (High-High)

Description of Change

ITS 3.3.2, Function 5.b, Feedwater Isolation - SG Level (High-High), will use an "Allowable Value" (i.e., as-found setpoint) as the Limiting Safety System Setting. As described in the Bases for CTS 3.5, IP2 uses the combination of this nominal trip setpoint and an associated 'administrative limit' which is controlled outside of the Technical Specifications to establish trip function Operability. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

Justification for Change

Adds requirement for Operability and Surveillance testing of ITS 3.3.2, Function 5.b, Feedwater Isolation - SG Water Level (High-High), because this Function is assumed to terminate an excessive heat removal due to feedwater system malfunction event in conjunction with reactor protection which is provided by overpower and overtemperature protection (high neutron flux, overtemperature delta T and overpower delta T trips).

Using the CTS "administrative limit" (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS) is an administrate change with no impact on safety. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

A.28.f **3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation**

Rev. 7 **Category** Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.2, Function 6.b, Auxiliary Feedwater - SG Water Level - low-low

Description of Change

CTS Table 3.5-1, Item 6, establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for the SG Water Level - low-low function at greater than or equal to 7% of the narrow range instrument span. As described in the Bases for CTS 3.5, IP2 uses the combination of this nominal trip setpoint and an associated 'administrative limit' which is controlled outside of the Technical Specifications to establish trip function Operability. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

ITS 3.3.2, Function 6.b, Auxiliary Feedwater - SG Water Level - low-low, will use the CTS "administrative limit," which is equivalent to the current licensing basis "Allowable Value," (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS). Use of the "Allowable Value," as the LSSS required to be in the Technical Specifications by 10 CFR 50.36(c)(1), is consistent with the guidance provided in Regulatory Guide 1.105, 'Setpoints for Safety-Related Instrumentation.'

In conjunction with the change which will include the allowable value in the ITS, IP2 will elect the option described in STS (NUREG-1431) to maintain the nominal trip setpoint (i.e., as-left limit) in a licensee controlled document. Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.4.

Justification for Change

Using the CTS "administrative limit" (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS) is an administrate change with no impact on safety. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.4.

A.30.f **3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation**

Rev. 7 **Category** Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.2, Function 6.d. Auxiliary Feedwater-Station Blackout (SBO) (Undervoltage Bus 5A or 6A)

Description of Change

CTS Table 3.5-1, Item 7, Station Blackout (Undervoltage), establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for CTS Table 3.5-3, Item 4.c, (Auxiliary Feedwater) Station Blackout (Start Motor Driven and Steam Driven Pumps) at greater than or equal to 40% of nominal voltage (i.e., 40% of 480 V). As described in the Bases for CTS 3.5, IP2 uses the combination of this nominal trip setpoint and an associated 'administrative limit' which is controlled outside of the Technical Specifications to establish trip function Operability. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

LCO 3.3.2, Function 6.d, Auxiliary Feedwater SBO (Emergency Bus 5A or 6A) establishes requirements for the SBO function by referencing LCO 3.3.5 except for Applicability. The requirements for allowable values for LCO 3.3.2, Function 6.d, Auxiliary Feedwater SBO (Emergency Bus 5A or 6A) are the same as those required by LCO 3.3.5, "LOP DG Start Instrumentation." ITS 3.3.5, 480 V Bus Station Blackout (SBO) Function - LOP DG Start Instrumentation, will use the CTS "administrative limit," which is equivalent to the current licensing basis "Allowable Value," (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS). Use of the "Allowable Value," as the LSSS required to be in the Technical Specifications by 10 CFR 50.36(c)(1), is consistent with the guidance provided in Regulatory Guide 1.105, 'Setpoints for Safety-Related Instrumentation.'

In conjunction with the change which will include the allowable value in the ITS, IP2 will elect the option described in STS (NUREG-1431) to maintain the nominal trip setpoint (i.e., as-left limit) in a licensee controlled document. Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.4.

Justification for Change

Using the CTS "administrative limit" (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS) is an administrate change with no impact on safety. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.4.

A.31.b 3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation

Rev 1 Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation of requirements for number of channels for:
ITS 3.3.2, Function 6.e. Auxiliary Feedwater - Trip of Main Boiler Feedwater Pump

Description of Change

CTS Table 3.5-3, Function 4.d, requires 1 operable channel with a minimum degree of redundancy of zero (See ITS 3.3.2, DOC A.37). The IP2 design is that a single channel associated with each operating MBFP will start both motor driven AFW pumps. CTS Table 3.5-3, Item 4.d, does not require any allowance for single failure.

ITS Function 6.e is revised to require 1 channel per operating main feed pump. Therefore, ITS 3.3.2, Function 6.e, is more restrictive (See 3.3.2, DOC M.9).

Justification for Change

Requiring two Operable channels (i.e., one Operable channel associated with each Operating feedwater pump) is a more restrictive change that is justified in DOC M.9.

A.31.c 3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation

Rev 7 Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Required Actions for one inoperable channel for:
ITS 3.3.2, Function 6.e. Auxiliary Feedwater - Trip of Main Boiler Feedwater Pump

Description of Change

For a loss of redundancy for the Auxiliary Feedwater - Trip of Main Boiler Feedwater Pump, CTS does not specify any actions because CTS Table 3.5-3 only requires 1 operable channel with a minimum degree of redundancy of zero for this function (See 3.3.2, DOC M.9).

In conjunction with the revised requirement for 1 channel per operating main feed pump, when MBFP trip channels are inoperable, Required Action H.1, verifies immediately that one channel associated with an operating MBFP is OPERABLE to ensure that there is no loss of function. If both MBFPs are operating, Required Action H.2.1 allows 48 hours to restore redundancy by requiring one channel associated with each operating MBFP to be OPERABLE. Continued operation without redundant channels when only MBFP is operating is acceptable because this is a backup method for starting AFW and other Functions, in particular SG Water Level -low-low, provide the primary protection against a loss of heat sink.

The IP2 plant design for this Function is not addressed in WCAP-10271 even after requirements were revised to require 1 channel per operating main feed pump. However, the allowable out of service times and surveillance test intervals are more conservative than CTS requirements (See 3.3.2, DOC M.9), accident scenarios are protected by Functions addressed in WCAP-10271, and the requirements specified in ITS 3.3.2 are consistent with plant design as described in the UFSAR.

Justification for Change

The 48 hour allowable out of service time to restore an inoperable channel is acceptable based on current licensing basis. The IP2 plant design for this Function is not addressed in WCAP-10271 even after requirements were revised to require 1 channel per operating feedwater pump. However, the allowable out of service times and surveillance test intervals are more conservative than CTS requirements accident scenarios are protected by Functions addressed in WCAP-10271, and the requirements specified in ITS 3.3.2 are consistent with plant design as described in the UFSAR.

A.31.f 3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation

Rev. 7 Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.2, Function 6.e. Auxiliary Feedwater - Trip of Main Boiler Feedwater Pump

Description of Change

CTS does not identify a limiting safety system setting for this function. Each turbine driven MBFP is equipped with a pressure switch on the control oil line for the speed control system. A low pressure signal (i.e., essentially 0 psig) from this pressure switch indicates a trip of that pump. As described in the Bases for CTS 3.5, IP2 uses the combination of this nominal trip setpoint and an associated 'administrative limit' which is controlled outside of the Technical Specifications to establish trip function Operability. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

ITS 3.3.2, Function 6.e. Auxiliary Feedwater - Trip of Main Boiler Feedwater Pump, will use the CTS "administrative limit," which is equivalent to the current licensing basis "Allowable Value," (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS). Use of the "Allowable Value," as the LSSS required to be in the Technical Specifications by 10 CFR 50.36(c)(1), is consistent with the guidance provided in Regulatory Guide 1.105, 'Setpoints for Safety-Related Instrumentation.'

In conjunction with the change which will include the allowable value in the ITS, IP2 will elect the option described in STS (NUREG-1431) to maintain the nominal trip setpoint (i.e., as-left limit) in a licensee controlled document. Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.4.

Justification for Change

This change is needed to ensure that calibration error and drift of the pressure switch do not allow the switch to be considered operable at 0 psig or below.

Using the CTS "administrative limit" (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS) is an administrate change with no impact on safety. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

A.40 3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation

Rev. 0 Category Administrative: No Technical Changes

DOC Summary:

Clarifies how ITS combination of requirements for number of Operable channels and that an inoperable channel is placed in trip maintains the CTS requirement for minimum number of Operable channels and minimum degree of redundancy with no explicit requirement that an inoperable channel is placed in trip.

Description of Change

CTS Tables 3.5-2, 3.5-3 and 3.5-4 establish minimum requirements for protective instrumentation Operability by mandating both a minimum number of operable channels and a minimum degree of redundancy.

Minimum degree of redundancy is defined in CTS 1.5 as the difference between the number of operable channels and the number of channels which when tripped will cause an automatic system trip (i.e., number of Operable channels minus number of channels to trip equals the degree of redundancy). An Operable channel is a channel that will generate a single protective action signal when required by a plant condition; therefore, a channel in trip is not considered Operable.

Using these definitions and CTS requirements for a minimum number of Operable channels and a minimum degree of redundancy, CTS allows plant operation to continue indefinitely with an inoperable channel only if the required minimum level of channels (function) is maintained and the required level of redundancy (failure tolerance) is maintained. This is achieved by placing the inoperable channel in trip. Therefore, CTS 3.5.3, in conjunction with CTS 1.5, specifies that the requirements for minimum Operable channels and minimum degree of redundancy must be maintained by placing an inoperable channel in trip.

Justification for Change:

This is an administrative change with no adverse impact on safety because there is no change to the existing requirements except as identified and justified in the discussion associated with each Function.

L.1 3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation

Rev. 7 Category Not Used:

DOC Summary:

Not Used.

Description of Change

Not Used.

Justification for Change:

Not Used.

L.2 3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation

Rev. 1 Category Not Used:

DOC Summary:

Not Used.

Description of Change

Not Used.

Justification for Change:

Not Used.

LA.4 <u>3.3.2: Engineered Safety Feature Actuation System (ESFAS) Instrumentation</u>

Rev. 7 <u>Category</u> Relocated Detail (Type 3): Relocates Procedural Details for Meeting TS Requirements and

<u>DOC Summary:</u>

Relocates the CTS nominal trip setpoints (i.e., as-left limits) to plant procedures because IP2 ITS will use the "Allowable Value" instead of the nominal trip setpoint as the limiting safety system setting (LSSS) that is required to be in the Technical Specifications by 10 CFR 50.36(c)(1).

<u>Description of Change</u>

IP2 CTS uses the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting (LSSS) that is required to be in the Technical Specifications by 10 CFR 50.36(c)(1) for the Reactor Protection System, Engineered Safety Feature Actuation System, and Loss of Power (LOP) Diesel Generator Start Instrumentation.

IP2 ITS LCO 3.3.1, RPS Instrumentation, LCO 3.3.2, ESFAS Instrumentation, and LCO 3.3.5, LOP DG Start Instrumentation, will use the "Allowable Value," as the LSSS required to be in the Technical Specifications by 10 CFR 50.36(c)(1). Using the "Allowable Value" as the LSSS is consistent with the guidance provided in Regulatory Guide 1.105, 'Setpoints for Safety-Related Instrumentation,' and STS (NUREG-1431).

In conjunction with the change, IP2 will elect the option described in STS (NUREG-1431) to maintain the nominal trip setpoint (i.e., as-left limit) in a licensee controlled document. Relocation of the nominal trip setpoint currently in the CTS to plant procedures is a less restrictive administrative change.

<u>Justification for Change</u>

This change is acceptable because IP2 ITS will use the "Allowable Value" instead of the nominal trip setpoint as the limiting safety system setting (LSSS) that is required to be in the Technical Specifications by 10 CFR 50.36(c)(1). Using the "Allowable Value" instead of the nominal trip setpoint as the LSSS is consistent with the guidance provided in Regulatory Guide 1.105, 'Setpoints for Safety-Related Instrumentation,' and STS (NUREG-1431).

BASES

APPLICABLE SAFETY ANALYSES (continued)

PAM instrumentation that meets the definition of Type A in Regulatory Guide 1.97 satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii). Category I, non-Type A, instrumentation must be retained in TS because it is intended to assist operators in minimizing the consequences of accidents. Therefore, Category I, non-Type A, variables are important for reducing public risk.

LCO

The PAM instrumentation LCO provides OPERABILITY requirements for Regulatory Guide 1.97 Type A monitors, which provide information required by the control room operators to perform certain manual actions specified in the unit Emergency Operating Procedures. These manual actions ensure that a system can accomplish its safety function, and are credited in the safety analyses. Additionally, this LCO addresses Regulatory Guide 1.97 instruments that have been designated Category I, non-Type A.

The OPERABILITY of the PAM instrumentation ensures there is sufficient information available on selected unit parameters to monitor and assess unit status following an accident. This capability is consistent with the recommendations of Reference 2.

LCO 3.3.3 requires at least two OPERABLE channels for most Functions. However, some functions, such as the RCS hot leg temperature and RCS cold leg temperature, require only one channel because they credit a required diverse function as a redundant channel. Two OPERABLE channels ensure no single failure prevents operators from getting the information necessary for them to determine the safety status of the unit, and to bring the unit to and maintain it in a safe condition following an accident.

Furthermore, OPERABILITY of two channels allows a CHANNEL CHECK during the post accident phase to confirm the validity of displayed information. More than two channels may be required for some functions if the IP2 Regulatory Guide 1.97 analyses (Ref. 4) determined that failure of one accident monitoring channel results in information ambiguity (that is, the redundant displays disagree) that could lead operators to defeat or fail to accomplish a required safety function.

Table 3.3.3-1 provides a list of variables typical of those identified by the IP2 Regulatory Guide 1.97 (Ref. 4) analyses. Table 3.3.3-1 includes all Type A and Category I variables identified by the unit specific Regulatory Guide 1.97 analyses, as amended by the NRC's SER (Ref. 1).

BASES

LCO (continued)

11. Pressurizer Level

Pressurizer Level is a Type A, Category I Function that is used to determine whether to terminate SI, if still in progress, or to reinitiate SI if it has been stopped. Knowledge of pressurizer water level is also used to verify the unit conditions necessary to establish natural circulation in the RCS and to verify that the unit is maintained in a safe shutdown condition.

This LCO is satisfied by the OPERABILITY of any two of the pressurizer level instruments designated LT-459, LT-460 and LT-461. Each channel has a range from the upper tap to the lower tap of the pressurizer which covers 85% of the pressurizer span.

12. Steam Generator Water Level (Narrow Range)

SG Water Level (narrow range) is a Type A, Category I Function. This Function is provided to monitor operation of decay heat removal via the SGs.

Each SG has three narrow range transmitters which span a range from the top of the tube bundles up to the moisture separator.

The LCO requirement for SG Level (narrow range) is satisfied by any two of the level instruments for each SG in the following list:

SG 21	SG 22	SG 23	SG 24
LT-417A	LT-427A	LT-437A	LT-447A
LT-417B	LT-427B	LT-437B	LT-447B
LT-417C	LT-427C	LT-437C	LT-447C

13. Steam Generator Water Level (Wide Range)

SG Water Level (wide range) is a Type B, Category I Function. Each SG has one wide range transmitter which spans a range from the tube sheet up to the moisture separator.

SG Water Level (Wide Range) is used to:

- identify the ruptured SG following a tube rupture,
- verify that the intact SGs are an adequate heat sink for the reactor,

BASES

LCO (continued)

15, 16, 17, 18. Core Exit Temperature

Core Exit Temperature is a Type A, Category III Function that is provided for verification and long term surveillance of core cooling.

Core exit temperature also serves as a redundant channel for the RCS Hot Leg Temperature (Function 1).

Core exit temperature is monitored by the core exit thermocouples (CETs). A total of 65 thermocouples are installed at preselected core locations to provide core exit temperature data up to 2300°F. There are two trains of CETs, one to process data for 34 thermocouples and the other for the remaining 31. The two trains receive power from redundant instrument busses. Two display units (one for each train) are provided on the central control room accident assessment panels. Each presents a graphic core location map with an alphanumeric display of core exit temperatures.

This LCO is satisfied by having 2 trains, each with a minimum of 2 qualified CETS (i.e., 4 CETs total) in each of the four quadrants. Requiring 2 qualified CETs in each train in each of the four quadrants provides assurance that sufficient CETs are available to support evaluation of core radial decay power distribution. Each pairing of 2 CETs from the same train in each quadrant is considered a separate function.

19. Auxiliary Feedwater Flow

AFW Flow is a Type A, Category II Function that is provided to monitor operation of decay heat removal via the SGs.

AFW flow is used three ways: to verify delivery of AFW flow to the SGs if SG narrow range level indicators are off scale low; to determine whether to terminate SI if still in progress, in conjunction with SG water level (narrow range); and to regulate AFW flow so that the SG tubes remain covered.

The LCO requirement for AFW flow indication is satisfied by OPERABILITY of the following 4 flow transmitters:

SG 21	SG 22	SG 23	SG 24
FT-1200	FT-1201	FT-1202	FT-1203

BASES

LCO (continued)

Two channels are required to be Operable for redundancy. The subcooling margin monitor readout on the plant computer can be used as a substitute for the control room panel readout of the RCS Subcooling Margin Monitor.

22. Refueling Water Storage Tank (RWST) Level

RWST Level is a Type A, Category II Function that is used to confirm RWST level prior to the manual switchover to the cold leg recirculation phase that is initiated when the RWST level has reached the low low alarm setpoint and sufficient coolant inventory to support pump operation in recirculation mode is verified in the containment.

Two channels of RWST Level indication are required consistent with LCO 3.5.4, "Refueling Water Storage Tank," requirements for OPERABILITY of two channels of the RWST level low low alarm. This is required because the IP2 ESFAS design does not include automatic switchover from the safety injection mode to the recirculation mode of operation based on low low level in the RWST coincident with a safety injection signal.

The LCO requirement for two channels of RWST level indication is satisfied by the OPERABILITY of LT-920 and LT-5751.

APPLICABILITY

The PAM instrumentation LCO is applicable in MODES 1, 2, and 3. These variables are related to the diagnosis and pre-planned actions required to mitigate DBAs. The applicable DBAs are assumed to occur in MODES 1, 2, and 3. In MODES 4, 5, and 6, unit conditions are such that the likelihood of an event that would require PAM instrumentation is low; therefore, the PAM instrumentation is not required to be OPERABLE in these MODES.

ACTIONS

A Note has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed on Table 3.3.3-1. The Completion Time(s) of the inoperable channel(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

BASES

ACTIONS (continued)

A.1

Condition A applies when one or more Functions have one required channel or train that is inoperable. Required Action A.1 requires restoring the inoperable channel to OPERABLE status within 30 days. The 30 day Completion Time is based on operating experience and takes into account the remaining OPERABLE channel (or in the case of a Function that has only one required channel, other non-Regulatory Guide 1.97 instrument channels to monitor the Function), the passive nature of the instrument (no critical automatic action is assumed to occur from these instruments), and the low probability of an event requiring PAM instrumentation during this interval.

B.1

Condition B applies when the Required Action and associated Completion Time for Condition A are not met. This Required Action specifies initiation of actions in Specification 5.6.6, which requires a written report to be submitted to the NRC immediately. This report discusses the results of the root cause evaluation of the inoperability and identifies proposed restorative actions. This action is appropriate in lieu of a shutdown requirement since alternative actions are identified before loss of functional capability, and given the likelihood of unit conditions that would require information provided by this instrumentation.

C.1

Condition C applies when one or more Functions have two or more inoperable required channels or trains (i.e., two channels or trains inoperable in the same Function). For Functions 1 and 2, Condition C applies when the one required channel is inoperable and there are no OPERABLE channels of the diverse Function that provides redundant indication. Required Action C.1 requires restoring one or more channel in the Function(s) to OPERABLE status within 7 days so that Condition C is no longer applicable. The Completion Time of 7 days is based on the relatively low probability of an event requiring PAM instrument operation and the availability of alternate means to obtain the required information. Continuous operation with two required channels inoperable in a Function is not acceptable because the alternate indications may not fully meet all performance qualification requirements applied to the PAM instrumentation. Therefore, requiring restoration of one inoperable channel of the Function limits the risk that the PAM Function will be in a degraded condition should an accident occur.

BASES

ACTIONS (continued)

E.1 and E.2

If the Required Action and associated Completion Time of Condition C are not met and Table 3.3.3-1 directs entry into Condition E, the unit must be brought to a MODE where the requirements of this LCO do not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and MODE 4 within 12 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

F.1

At Indian Point 2, Function 4 (Reactor Vessel Level Indication System) and Function 10 (Containment Hydrogen Monitor) are not classified as Type A variables based on the evaluations listed in Reference 1. Additionally, alternate methods or diverse variables providing adequate information to make required assessments are available to operators even if these functions are not available. Therefore, plant shutdown within 7 days is not warranted if more than one channel of these Functions are not OPERABLE.

Function 9 (Containment Area Radiation - High Range) and Function 14 (Condensate Storage Tank Level) are Type A variables; however, alternate methods for monitoring these variables are available. Therefore, plant shutdown within 7 days is not warranted if more than one channel of these Functions are not OPERABLE.

If these alternate means are used to monitor a parameter, the Required Action is not to shut down the unit but rather to follow the directions of Specification 5.6.6, in the Administrative Controls section of the TS. The report provided to the NRC should discuss the alternate means used, describe the degree to which the alternate means are equivalent to the installed PAM channels, justify the areas in which they are not equivalent, and provide a schedule for restoring the normal PAM channels.

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that SR 3.3.3.1 and SR 3.3.3.3 apply to each PAM instrumentation Function in Table 3.3.3-1.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.3.1

Performance of the CHANNEL CHECK once every 31 days ensures that a gross instrumentation failure has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION. The high radiation instrumentation should be compared to similar unit instruments located throughout the unit.

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including isolation, indication, and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit. If the channels are within the criteria, it is an indication that the channels are OPERABLE.

As specified in the SR, a CHANNEL CHECK is only required for those channels that are normally energized. Instruments that are normally isolated or normally not in service are considered de-energized.

The Frequency of 31 days is based on operating experience that demonstrates that channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the LCO required channels.

SR 3.3.3.2 and SR 3.3.3.3

A CHANNEL CALIBRATION is performed every 92 days for the hydrogen monitor and RWST level and every 24 months, or approximately at every refueling for all other Table 3.3.3-1 Functions. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to measured parameter with the necessary range and accuracy. Whenever a sensing element is replaced, the next required CHANNEL CALIBRATION of the Core Exit thermocouple

BASES

SURVEILLANCE REQUIREMENTS (continued)

sensors is accomplished by an inplace cross calibration that compares the other sensing elements with the recently installed sensing element. The Frequency is based on operating experience and consistency with the typical industry refueling cycle.

REFERENCES

1. Safety Evaluation by the Office of Nuclear Reactor Regulation Regarding Conformance to Regulatory Guide 1.97 for Consolidated Edison Company of New York, Inc. Indian Point Nuclear Generating Unit No. 2, Docket No. 50-247, September 27, 1990.

2. Regulatory Guide 1.97, December 1980.

3. NUREG-0737, Supplement 1, "TMI Action Items."

4. UFSAR, Section 7.1.5

BASES

SURVEILLANCE REQUIREMENTS (continued)

The Frequency of 24 months is based upon operating experience and consistency with the typical industry refueling cycle.

SR 3.3.4.4

SR 3.3.4.4 is a verification of the proper operation of the reactor trip breaker (RTB) and reactor trip bypass breaker (RTBB) local open/closed indication every 24 months. This test should verify the OPERABILITY of the RTB and RTBB open and closed indication by actuating the RTBs. This SR can be satisfied by verification of the RTB local indication during performance of RTB testing required by LCO 3.3.1, "Reactor Protection System (RPS) Instrumentation."

REFERENCES

1. 10 CFR 50, Appendix A, GDC 19.
2. UFSAR, Section 7.7.3 and 8.3.

Table B 3.3.4-1 (page 1 of 2)
Remote Shutdown Instrumentation and Controls

FUNCTION/INSTRUMENT OR CONTROL PARAMETER			REQUIRED NUMBER OF FUNCTIONS
1.	REACTIVITY CONTROL		
	a.	Source Range Neutron Flux (NI-5143-1).	1
	b.	Reactor Trip and Bypass Breaker Position.	1 per breaker
	c.	Reactor Trip & Bypass Breaker Trip Switch; or 21 MG Set & 22 MG Set Trip Switch.	1 per breaker; or 1 per train
	d.	Seal Injection Flow (FI-144, FI-143, FI-116 and FI-115)	1 per RCP
2.	REACTOR COOLANT SYSTEM PRESSURE CONTROL		
	a.	21 Pressurizer Backup Heater Local/Remote transfer switch.	1
	b.	Pressurizer Pressure (PI-3105-1).	1
3.	DECAY HEAT REMOVAL via STEAM GENERATORS		
	a.	Hot Leg Temperature. (TI-5139 for Loop 21 and TI-5141 for Loop 22)	2
	b.	Cold Leg Temperature. (TI-5140 for Loop 21 and TI-5142 for Loop 22)	2
	c.	SG Pressure. (PI-1353, PI-1354, PI-1355 and PI-1356)	1 per SG
	d.	SG Level. (LI-5001-1 for 21 SG and LI-5002-1 for 22 SG)	2
	e.	CST Level.	1
	f.	Atmospheric Steam Dump Valve controls. (Local nitrogen control stations in AFW Pump Building)	1
	g.	Auxiliary Feedwater Pump 21. (Transfer switch EDC5 and breaker 1B)	1

Table B 3.3.4-1 (page 2 of 2)
Remote Shutdown Instrumentation and Controls

FUNCTION/INSTRUMENT OR CONTROL PARAMETER	REQUIRED NUMBER OF FUNCTIONS
h. AFW Pump suction and discharge pressure.	1 each per pump
i. Transfer switches for 21 RHR and 22 RHR.	1 per pump
4. RCS INVENTORY CONTROL	
a. Pressurizer Level (LI-3101-1)	1
b. RWST Level (LI-921)	1
c. Charging Pump 23 (Transfer switch EDC4 and breaker 1M)	1
5. SUPPORT EQUIPMENT	
a. CCW Flow from RCP seals (thermal barriers) (FIC-625)	1
b. CCW flow to Charging Pumps (FI-637)	1
c. CCW flow to RHR Pumps (FIC-645, FIC 646)	2
d. Service Water Pumps (Transfer switch EDG3 and breaker 1M for SW Pump 23) (Transfer switch EDG4 and breaker 3M for SW Pump 24)	2
e. Component Cooling Water Pump (Transfer switch EDF9 and breaker 2B for CCW Pump 23)	1
f. Service Water Pressure at CCW-HX Inlet (PI-1276, PI-1277)	2

3.3 INSTRUMENTATION

3.3.5 Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation

LCO 3.3.5 The following LOP DG start instrumentation shall be OPERABLE:

a. Two channels per bus of the 480 V bus Undervoltage Function on buses 5A, 2A, 3A and 6A;

b. Two channels per bus of the 480 V bus Degraded Voltage Function on buses 5A, 2A, 3A and 6A;

c.1 Three channels per bus of the Station Blackout (SBO) Function on buses 5A and 6A when in MODE 1, 2, 3 and 4; and

c.2 Three channels per bus of the Station Blackout (SBO) Function on either bus 5A or 6A when in MODE 5 and 6.

APPLICABILITY: MODES 1, 2, 3, and 4,
When associated DG is required to be OPERABLE by LCO 3.8.2, "AC Sources - Shutdown."

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. - NOTE - Not applicable in MODE 5 or 6. One SBO channel inoperable on one bus.	A.1 Place channel in trip.	7 days

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. - NOTE - Not applicable in MODE 5 or 6. Two or more SBO channels inoperable on one bus with three OPERABLE SBO channels on the other bus. OR One SBO channel inoperable on both buses.	B.1	Restore to OPERABLE status at least three SBO channels on one bus and two SBO channels on the other bus.	48 hours
C. Required Action and Completion Time of Condition A or B not met.	C.1	Be in MODE 3.	6 hours
	AND		
	C.2	Be in MODE 5.	36 hours
D. - NOTE - Not applicable in MODE 1, 2, 3 or 4. One SBO channel inoperable on a required bus.	D.1	Place channel in trip.	48 hours
E. Two or more SBO channels inoperable on both buses in MODE 1, 2, 3 or 4. OR Required Action and Completion Time of D not met.	E.1	Enter applicable Condition(s) and Required Action(s) for all DGs inoperable.	Immediately

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
F. - NOTE - Separate Condition entry is allowed for each bus. One Undervoltage Function channel inoperable.	F.1	Restore channel to OPERABLE status.	6 hours
G. - NOTE - Separate Condition entry is allowed for each bus. One Degraded Voltage Function channel inoperable.	G.1	Place channel in trip.	1 hour
H. Required Action and associated Completion Time of Condition F or G not met. OR Two Undervoltage Function channels inoperable on one or more buses. OR Two Degraded Voltage Function channels inoperable on one or more buses.	H.1	Enter applicable Condition(s) and Required Action(s) for the associated DG(s) made inoperable by LOP DG start instrumentation.	Immediately

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.3.5.1	Perform CHANNEL CHECK of the 480 V bus Degraded Voltage Function.	12 hours
SR 3.3.5.2	Perform TADOT of the 480 V bus Degraded Voltage Function.	31 days
SR 3.3.5.3	Perform TADOT of each of the following: a. 480 V bus Undervoltage Function; and b. 480 V bus SBO Function.	24 months
SR 3.3.5.4	Perform ACTUATION LOGIC TEST of each of the following: a. 480 V bus Undervoltage Function; and b. 480 V bus SBO Function.	24 months
SR 3.3.5.5	Perform CHANNEL CALIBRATION with Allowable Values as follows: a. 480 V bus Undervoltage Function Allowable Value: ≥ 206.6 V with a time delay ≤ 3.7 seconds. b. 480 V bus Degraded Voltage Function Allowable Value: ≥ 419 V and ≤ 423 V with time delays as follows: i. ≤ 207 seconds (No SI Signal); and ii. ≥ 8.4 seconds and ≤ 11.6 seconds (Coincident SI). c. 480 V bus SBO Function Allowable Value: ≥ 198.6 V.	24 months

BASES

BACKGROUND (continued)

Degraded Voltage relays (i.e., channels), two channels per bus on 480 V buses 6A, 2A, 3A and 5A, will detect a degraded voltage condition on any of the four 480 V safeguards buses. Detection of a degraded voltage condition on a 480 V bus will open breakers on the associated bus that connect the 480 V bus to offsite power or the unit auxiliary transformer (i.e., plant main generator). The relays are combined in a two-out-of-two logic to prevent spurious actuation. A two-out-of-two logic for each bus is acceptable because redundancy is provided by the number of DGs available. The degraded voltage function actuation includes time delays to ensure proper coordination with plant electrical transients (large motor starts, fast transfers, etc.). As specified in the acceptance criteria for SR 3.3.5.5, the degraded voltage function will actuate after a short time delay if there is a concurrent safety injection signal and will actuate after a longer time delay if there is no concurrent safety injection signal. The allowable values for this function (including time delays) are established in accordance with Reference 2.

The LOP start actuation is described in UFSAR, Sections 7.5, 8.1 and 8.2 (Ref. 1).

Technical Specification Allowable Values are determined based on the relationship between an analytical limit and a calculated trip setpoint. A detailed discussion of the relative position of the safety limit, analytical limit, allowable value and the trip setpoint with respect to the normal plant operation point is presented in the Bases of LCO 3.3.1, "Reactor Protection System (RPS) Instrumentation."

A detailed description of the methodology used to calculate the channel and bistable device allowable value, including their explicit uncertainties, is provided in Reference 2.

APPLICABLE SAFETY ANALYSES

The LOP DG start instrumentation is required for the Engineered Safety Features (ESF) Systems to function in any accident with a loss of offsite power. Its design basis is that of the ESF Actuation System (ESFAS).

Accident analyses credit the loading of the DG based on the loss of offsite power during a loss of coolant accident (LOCA). The actual DG start has historically been associated with the ESFAS actuation. The DG loading has been included in the delay time associated with each safety system component requiring DG supplied power following a loss of offsite power.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The required channels of LOP DG start instrumentation, in conjunction with the ESF systems powered from the DGs, provide unit protection in the event of any of the analyzed accidents discussed in Reference 1, in which a loss of offsite power is assumed.

The delay times assumed in the safety analysis for the ESF equipment include the 10 second DG start delay, and the appropriate sequencing delay, if applicable. The response times for ESFAS actuated equipment in LCO 3.3.2 include the appropriate DG loading and sequencing delay.

Loss of the LOP DG Start Instrumentation Function could result in the delay of safety systems initiation when required. This could lead to unacceptable consequences during accidents. During the loss of offsite power the DG powers the motor driven auxiliary feedwater pumps. Failure of these pumps to start would leave only one turbine driven pump, as well as an increased potential for a loss of decay heat removal through the secondary system.

The LOP DG start instrumentation channels satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO for LOP DG start instrumentation requires that the following instrumentation is OPERABLE:

a. Two channels per bus of the 480 V bus Undervoltage Function on buses 5A, 2A, 3A and 6A. OPERABILITY requires that both the trip setpoint and the time delay are within the Allowable Values specified in SR 3.3.5.5. Either of the undervoltage relays will actuate the undervoltage function with additional redundancy provided by the number of DGs available. Additionally, an ESFAS safety injection signal will initiate all of the functions actuated by the undervoltage relays.

b. Two channels per bus of the 480 V bus Degraded Voltage Function on buses 5A, 2A, 3A and 6A. Both channels on each bus are required to be OPERABLE because relays are combined in a two-out-of-two logic to prevent spurious actuation. A two out of two logic for each bus is acceptable because redundancy is provided by the number of DGs available. OPERABILITY requires that both the trip setpoint and the time delay are within the allowable values specified in SR 3.3.5.5.

BASES

LCO (continued)

c.1 Three channels per bus of the Station Blackout (SBO) Function on both bus 5A and 6A are required when in MODE 1, 2, 3 and 4. Each set of three SBO undervoltage relays (i.e., channels) is considered a train because, if there is a loss of voltage on 480 V bus 5A or 6A, two out of the three SBO undervoltage relays associated with either train will actuate the undervoltage portion of the SBO function. The SBO actuation logic design, two out of three channels on bus 6A or two out of three on bus 5A, provides sufficient redundancy such that the three channels associated with either bus will actuate the SBO function in conjunction with any single active failure. Actuation logic for the SBO undervoltage function includes input from a safety injection signal and/or a plant trip. If either of these inputs is inoperable, all three channels with the associated train are inoperable. OPERABILITY requires that the trip setpoint is within the allowable values specified in SR 3.3.5.5.

c.2 Three channels per bus of the Station Blackout (SBO) Function on either bus 5A or 6A are required when in MODE 5 and 6. As explained in the Bases for LCO 3.8.2, "AC Sources - Shutdown," the Technical Specifications requirements ensure that the unit has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or all onsite power is not required. In MODE 5 and 6, operators have sufficient time to align a DG manually if the SBO function fails to automatically connect a DG to its 480 V bus.

APPLICABILITY

The LOP DG Start Instrumentation Functions are required in MODES 1, 2, 3, and 4 because ESF Functions are designed to provide protection in these MODES. Actuation in MODE 5 or 6 is required whenever a DG must be OPERABLE so that it can perform its function on an LOP or degraded power to the vital bus.

ACTIONS

In the event a channel's trip setpoint is found nonconservative with respect to the Allowable Value, or the channel is found inoperable, then the function that channel provides must be declared inoperable and the LCO Condition entered for the particular protection function affected.

BASES

ACTIONS (continued)

A.1

Condition A applies when one SBO channel on one bus is inoperable. In this Condition, the remaining two OPERABLE channels associated with the affected bus will still actuate the SBO function. Additionally, any two of the three OPERABLE channels associated with the other bus will also actuate the SBO function. Therefore, a Completion Time of 7 days to place the inoperable channel in trip provides adequate time to accomplish required repairs without any significant degradation of safety.

Condition A is modified by a Note stating that the Condition is not applicable in MODE 5 or 6. This note is necessary because three channels per bus of the Station Blackout (SBO) Function are required on either bus 5A or 6A when in MODE 5 and 6.

B.1

Condition B applies when two or more SBO channels on one bus are inoperable but all three SBO channels on the other bus are OPERABLE or when one SBO channel is inoperable on both buses. Note that inoperability of the input from a safety injection signal and/or a plant trip into the SBO actuation logic is equivalent to three inoperable channels on that bus. Therefore, if either of these inputs is inoperable, all three channels are inoperable.

In Condition B, either of the two OPERABLE channels associated with each bus or two OPERABLE channels associated with the OPERABLE bus will still actuate the SBO function on a loss of offsite power to 480 V buses 5A and 6A. Therefore, a Completion Time of 48 hours to restore at least one of the inoperable channels provides adequate time to accomplish required repairs without significant degradation of safety.

Condition B is modified by a Note stating that the Condition is not applicable in MODE 5 or 6. This note is necessary because three channels per bus of the Station Blackout (SBO) Function on either bus 5A or 6A are required when in MODE 5 and 6.

BASES

ACTIONS (continued)

C.1 and C.2

If the inoperable SBO channels cannot be restored to OPERABLE status within the required 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 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems.

D.1

Condition D applies when one SBO channel is inoperable on the required bus (i.e., either 480 V bus 5A or 6A) when in MODE 5 or 6. In this Condition, the two remaining OPERABLE SBO channels will accomplish the SBO function. A Completion Time of 48 hours to place the inoperable channel in trip is appropriate because operators have sufficient time to align a DG manually if the SBO function fails to automatically connect a DG to its 480 V bus when in MODE 5 and 6.

E.1

Condition E applies when two or more SBO channels on both buses are inoperable when in MODE 1, 2, 3 or 4. In this Condition, the SBO logic will not perform its required safety function and the DGs will not automatically supply the 480 V safeguards buses as assumed in the accident analysis. However, if an SI signal is not present, the DGs will start automatically but operator action will be required to align the DGs to the associated 480 V buses. Therefore, immediate entry into the applicable Condition(s) and Required Action(s) for all DGs inoperable is appropriate. Condition E applies when the Required Actions and Completion Time of Condition D are not met.

F.1

Condition F applies when one of the two channels of 480 V bus undervoltage function is inoperable. In this Condition, the associated DG will automatically connect to the associated 480 V bus on an undervoltage signal; however, the design redundancy for this function is lost. Therefore, Required Action F.1 allows 6 hours to restore the required channel to OPERABLE status before the affected DG must be declared inoperable in accordance with Required Action H.1. Condition F is modified by a Note explaining that separate condition entry is allowed for each 480 V bus.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.5.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit.

The Frequency is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the LCO required channels.

SR 3.3.5.2 and SR 3.3.5.3

SR 3.3.5.2 and SR 3.3.5.3 require performance of TADOTs. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable TADOT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. This test is performed every 31 days for the 480 V bus Degraded Voltage Function and every 24 months for the 480 V bus undervoltage function and the 480 V SBO function. The test checks trip devices that provide actuation signals directly, bypassing the analog process control equipment. For these tests, the relay trip setpoints are verified and adjusted as necessary. The Frequency is based on the known reliability of the relays and controls and the multichannel redundancy available, and has been shown to be acceptable through operating experience.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.5.4

SR 3.3.5.4 is the performance of an ACTUATION LOGIC TEST for the 480 V function and 480 V undervoltage function. This test is performed every 24 months which is consistent with the plant conditions needed to perform the test. This Test is performed in conjunction with the testing of LCO 3.3.2, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation," Function 6.d, Auxiliary Feedwater - Station Blackout. The Surveillance interval is acceptable based on instrument reliability and operating experience.

SR 3.3.5.5

SR 3.3.5.5 is the performance of a CHANNEL CALIBRATION.

The setpoints, as well as the response to a loss of voltage and a degraded voltage test, shall include a single point verification that the trip occurs within the required time delay.

A CHANNEL CALIBRATION is performed every 24 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 a measured parameter within the necessary range and accuracy.

The Frequency of 24 months is based on operating experience and consistency with the typical industry refueling cycle and is justified by the assumption of an 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

REFERENCES

1. UFSAR, Section 7,8 and 14.

2. Indian Point 2 Specification FIX-95-A-001, Guidelines For Preparation Of Instrument Loop Accuracy And Setpoint Determination Calculation.

Table 3.5-1

Engineered Safety Features Initiation Instrument Setting Limits

	No.	Functional Unit	Channel		Setting Limits	
	1.	High Containment Pressure (Hi Level)	Safety Injection		≤ 2.0 psig	
	2.	High Containment Pressure (Hi-Hi Level)	a. Containment Spray b. Steam Line Isolation		≤ 24 psig	
	3.	Pressurizer Low Pressure	Safety Injection		≥ 1833 psig	
	4.	High Differential Pressure Between Steam Lines	Safety Injection		≤ 155 psi	
SEE ITS 3.3.2	5.	High Steam Flow in 2/4 Steam Lines Coincident with Low T_{avg} or Low Steam Line Pressure	a. Safety Injection b. Steam Line Isolation		≤ 40% of full steam flow at zero load ≤ 40% of full steam flow at 20% load ≤ 110% of full steam flow at full load ≥ 540°F T_{avg} ≥ 525 psig steam line pressure	
	6.	Steam Generator Water Level (Low-Low)	Auxiliary Feedwater	A.7 ≥198.6V	≥ 7% of narrow range instrument span each steam generator	
LCO 3.3.5 SR 3.3.5.5	7.	Station Blackout (Undervoltage)	Auxiliary Feedwater		≥ 40% nominal voltage	LA.3
LCO 3.3.5 SR 3.3.5.5	8a.	480V Emergency Bus Undervoltage (Loss of Voltage)	------	A.3.f ≥206.6V Time delay ≤ 3.7 sec	220V + 100V, -20V 3 sec ± 1 sec	LA.3
LCO 3.3.5 SR 3.3.5.5	8b.	480V Emergency Bus Undervoltage (Degraded Voltage)	------	A.4.f ≥419 & ≤423V No SI: ≤ 207 sec SI: ≥8.4 & ≤11.6 sec	421V ± 6V 180 sec ± 30 sec (no SI) 10 sec ± 2 sec (coincident	LA.3 165

ITS Package Revision 2

ITS 3.3.5

Discussions of Changes:

A.3.f **3.3.5: Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation**

Rev. 7 Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.5, 480 V Bus Undervoltage Function - LOP DG Start Instrumentation

Description of Change

CTS Table 3.5-1, Item 8.a, 480 V Emergency Bus Undervoltage (Loss of Voltage), establishes the nominal trip setpoint as the limiting safety system setting (i.e., the as-left setpoint) for CTS Table 3.5-3, Item 3.a, 480 V Emergency Bus Undervoltage (Loss of Voltage) at greater than or equal to 200 V and less than or equal to 320 V with a time delay greater than or equal to 2 seconds and less than or equal to 4 seconds. As described in the Bases for CTS 3.5, IP2 uses the combination of this nominal trip setpoint and an associated 'administrative limit' which is controlled outside of the Technical Specifications to establish trip function Operability. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

ITS 3.3.5, 480 V Bus Undervoltage Function - LOP DG Start Instrumentation, will use the CTS "administrative limit," which is equivalent to the current licensing basis "Allowable Value," (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS). Use of the "Allowable Value," as the LSSS required to be in the Technical Specifications by 10 CFR 50.36(c)(1), is consistent with the guidance provided in Regulatory Guide 1.105, 'Setpoints for Safety-Related Instrumentation.'

In conjunction with the change which will include the allowable value in the ITS, IP2 will elect the option described in STS (NUREG-1431) to maintain the nominal trip setpoint (i.e., as-left limit) in a licensee controlled document. Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.3.

Justification for Change

Using the CTS "administrative limit" (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS) is an administrate change with no impact on safety. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.3.

A.4.f 3.3.5: Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation

Rev. 7 Category Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.5, 480 V Bus Degraded Voltage Function - LOP DG Start Instrumentation

Description of Change

CTS Table 3.5-1, Item 8.b, 480 V Emergency Bus Undervoltage (Degraded Voltage), establishes the nominal trip setpoint as the limiting safety system setting (i.e., the as-left setpoint) for CTS Table 3.5-3, Item 3.a, 480 V Emergency Bus Undervoltage (Loss of Voltage) as follows:

Degraded voltage without an ESFAS Safety Injection Signal: the setpoint is greater than or equal to 415 V and less than or equal to 427 V with a time delay at greater than or equal to 150 seconds and less than or equal to 210 seconds.

Degraded voltage with an ESFAS Safety Injection Signal: the setpoint is greater than or equal to 415 V and less than or equal to 427 V with a time delay at greater than or equal to 8 seconds and less than or equal to 12 seconds.

As described in the Bases for CTS 3.5, IP2 uses the combination of this nominal trip setpoint and an associated 'administrative limit' which is controlled outside of the Technical Specifications to establish trip function Operability. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

ITS 3.3.5, 480 V bus degraded voltage function - LOP DG Start Instrumentation, will use the CTS "administrative limit," which is equivalent to the current licensing basis "Allowable Value," (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS). Use of the "Allowable Value," as the LSSS required to be in the Technical Specifications by 10 CFR 50.36(c)(1), is consistent with the guidance provided in Regulatory Guide 1.105, 'Setpoints for Safety-Related Instrumentation.'

In conjunction with the change which will include the allowable value in the ITS, IP2 will elect the option described in STS (NUREG-1431) to maintain the nominal trip setpoint (i.e., as-left limit) in a licensee controlled document. Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.3.

Justification for Change

Using the CTS "administrative limit" (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS) is an administrate change with no impact on safety. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04, Part II.

Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.3.

A.7.f **3.3.5: Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation**

Rev. 7 **Category** Administrative: No Technical Changes

DOC Summary:

Adopts ITS presentation and organization of Allowable Values and Setpoints for:
ITS 3.3.5, 480 V Bus Station Blackout (SBO) Function - LOP DG Start Instrumentation

Description of Change

CTS Table 3.5-1, Item 7, Station Blackout (Undervoltage), establishes the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting for CTS Table 3.5-3, Item 4.c, (Auxiliary Feedwater) Station Blackout (Start Motor Driven and Steam Driven Pumps) at greater than or equal to 40% of nominal voltage (i.e., 40% of 480 V). As described in the Bases for CTS 3.5, IP2 uses the combination of this nominal trip setpoint and an associated 'administrative limit' which is controlled outside of the Technical Specifications to establish trip function Operability. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approved the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04 Part II.

ITS 3.3.5, 480 V Bus Station Blackout (SBO) Function - LOP DG Start Instrumentation, will use the CTS "administrative limit," which is equivalent to the current licensing basis "Allowable Value," (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS). Use of the "Allowable Value," as the LSSS required to be in the Technical Specifications by 10 CFR 50.36(c)(1), is consistent with the guidance provided in Regulatory Guide 1.105, 'Setpoints for Safety-Related Instrumentation.'

In conjunction with the change which will include the allowable value in the ITS, IP2 will elect the option described in STS (NUREG-1431) to maintain the nominal trip setpoint (i.e., as-left limit) in a licensee controlled document. Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.3.

Justification for Change:

Using the CTS "administrative limit" (i.e., as-found setpoint limit) as the ITS Limiting Safety System Setting (LSSS) is an administrate change with no impact on safety. As explained in the June 21, 1994, letter (TAC Number M86204) from Francis J Williams (NRC) to Stephen B. Bram (Con Ed) that approve the Bases for IP2 CTS 3.5, the "administrative limit" for IP2 serves the same function as the allowable value defined in the Standard Technical Specifications and plant setpoint methodology. "The CTS administrative limits were calculated using methodologies that conform to Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems," Revision 2, dated February 1986, and ISA-RP67.04 Part II.

Relocation of the nominal trip setpoint currently in the CTS to plant procedures is justified in DOC LA.3.

L.1 **3.3.5: Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation**

Rev. 7 **Category** Not Used:

DOC Summary:

Not Used.

Description of Change

Not Used.

Justification for Change:

Not Used.

LA.3 3.3.5: Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation

Rev. 7 Category Relocated Detail (Type 3): Relocates Procedural Details for Meeting TS Requirements and

DOC Summary:

Relocates the CTS nominal trip setpoints (i.e., as-left limits) to plant procedures because IP2 ITS will use the "Allowable Value" instead of the nominal trip setpoint as the limiting safety system setting (LSSS) that is required to be in the Technical Specifications by 10 CFR 50.36(c)(1).

Description of Change

IP2 CTS uses the nominal trip setpoint (i.e., as-left limit) as the limiting safety system setting (LSSS) that is required to be in the Technical Specifications by 10 CFR 50.36(c)(1) for the Reactor Protection System, Engineered Safety Feature Actuation System, and Loss of Power (LOP) Diesel Generator Start Instrumentation.

IP2 ITS LCO 3.3.1, RPS Instrumentation, LCO 3.3.2, ESFAS Instrumentation, and LCO 3.3.5, LOP DG Start Instrumentation, will use the "Allowable Value," as the LSSS required to be in the Technical Specifications by 10 CFR 50.36(c)(1). Using the "Allowable Value" as the LSSS is consistent with the guidance provided in Regulatory Guide 1.105, 'Setpoints for Safety-Related Instrumentation,' and STS (NUREG-1431).

In conjunction with the change, IP2 will elect the option described in STS (NUREG-1431) to maintain the nominal trip setpoint (i.e., as-left limit) in a licensee controlled document. Relocation of the nominal trip setpoint currently in the CTS to plant procedures is a less restrictive administrative change.

Justification for Change

This change is acceptable because IP2 ITS will use the "Allowable Value" instead of the nominal trip setpoint as the limiting safety system setting (LSSS) that is required to be in the Technical Specifications by 10 CFR 50.36(c)(1). Using the "Allowable Value" instead of the nominal trip setpoint as the LSSS is consistent with the guidance provided in Regulatory Guide 1.105, 'Setpoints for Safety-Related Instrumentation,' and STS (NUREG-1431).

3.3 INSTRUMENTATION

3.3.6 Containment Purge System and Pressure Relief Line Isolation Instrumentation

LCO 3.3.6 The Containment Purge System and Pressure Relief Line Isolation instrumentation for each Function in Table 3.3.6-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3 and 4,
During movement of recently irradiated fuel assemblies within containment.

ACTIONS

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

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One radiation monitoring channel inoperable.	A.1	Restore the affected channel to OPERABLE status.	7 days
B. - NOTE - Only applicable in MODE 1, 2, 3, or 4. One or both automatic actuation trains inoperable. <u>OR</u> Two radiation monitoring channels inoperable. <u>OR</u> Required Action and associated Completion Time of Condition A not met.	B.1	Enter applicable Conditions and Required Actions of LCO 3.6.3, "Containment Isolation Valves," for containment purge system and pressure relief line isolation valves made inoperable by isolation instrumentation.	Immediately

B 3.3 INSTRUMENTATION

B 3.3.6 Containment Purge System and Pressure Relief Line Isolation Instrumentation

BASES

BACKGROUND

Containment purge system and pressure relief line isolation instrumentation closes the containment isolation valves in the Containment Purge System (containment purge supply line and containment purge exhaust line) and the Containment Pressure Relief Line. This action isolates the containment atmosphere from the environment to minimize releases of radioactivity in the event of an accident.

A detailed description of the Containment Purge System (containment purge supply line and containment purge exhaust line) and the Containment Pressure Relief Line is provided in the Background of the Bases for Technical Specification 3.6.3, "Containment Isolation Valves."

Both the containment purge supply and exhaust isolation valves (FCV-1170, FCV-1171, FCV-1172, and FCV-1173) and the containment pressure relief line isolation valves (PCV-1190, PCV-1191 and PCV-1192) close when high radiation levels are detected by the Containment Air Particulate Monitor (R-41) or Containment Radioactive Gas Monitor (R-42). The Containment Phase A Isolation ESFAS signal (LCO 3.3.2, Function 3.a) and Containment Spray ESFAS signal (LCO 3.3.2, Function 2) also cause closure of the containment purge isolation valves and the containment pressure relief isolation valves. Although not required to satisfy Technical Specifications, containment purge and containment pressure relief are also isolated when high gas radiation levels are detected in the plant vent (R-44). A failure of the R-44 monitor does not affect operation of the isolation function performed by R-41 and R-42.

APPLICABLE SAFETY ANALYSES

The safety analyses assume that the containment remains intact with penetrations unnecessary for core cooling isolated early in the event, within approximately 60 seconds.

In MODES 1, 2, 3 and 4, isolation instrumentation for the containment purge supply line, containment purge exhaust line and the containment pressure relief line may be open, as needed, for pressure control, ALARA or air quality considerations for personnel entry, or for Surveillances that require the valves to be open consistent with Surveillance Requirements 3.6.3.1 and 3.6.3.2. This is acceptable because the containment purge (supply and exhaust) lines and pressure relief line are equipped with redundant containment isolation valves that are automatically closed upon receipt of a

BASES

APPLICABLE SAFETY ANALYSES (continued)

During movement of recently irradiated fuel (i.e., fuel assemblies that have been part of a critical reactor in the previous 100 hours), the relaxations justified in Reference 2 do not apply. Therefore, during movement of recently irradiated fuel assemblies, LCO 3.9.3, "Containment Penetrations," establishes requirements for containment closure that minimize any release via Containment Purge System and Pressure Relief Line Isolation to the environment resulting from a fuel handling accident that occurs when the reactor has been subcritical for less than the 100 hours assumed in Reference 2. Therefore, LCO 3.3.6 requirements are applicable during the movement of recently irradiated fuel.

The containment purge supply line, containment purge exhaust line and the containment pressure relief line isolation instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii)

LCO

The LCO requirements ensure that the instrumentation necessary to initiate containment purge supply line, containment purge exhaust line and the containment pressure relief line isolation, listed in Table 3.3.6-1, is OPERABLE.

1. <u>Automatic Actuation Logic and Actuation Relays</u>

The LCO requires two trains of Automatic Actuation Logic and Actuation Relays OPERABLE to ensure that no single random failure can prevent automatic actuation.

The Automatic Actuation Logic and Actuation Relays Function is required to be OPERABLE to support the OPERABILITY of all of the functions that isolate the containment purge system and pressure relief line (gaseous and particulate radiation monitors (R-42 and R-41) and ESFAS containment phase A isolation and containment spray initiation signals). There are two trains of automatic actuation logic and actuation relays for the containment purge system and pressure relief line. If one or more of the Containment Spray or Phase A isolation Functions becomes inoperable in such a manner that only the Containment Purge Isolation Function is affected, the Conditions applicable to their Containment Spray and Phase A isolation Functions need not be entered. The less restrictive Actions specified for inoperability of the Containment Purge and Pressure Relief Line Isolation Functions specify sufficient compensatory measures for this case.

BASES

LCO (continued)

2. Containment Radiation

The LCO specifies two required channels of radiation monitors to ensure that the radiation monitoring instrumentation necessary to initiate Containment Purge Isolation remains OPERABLE. The requirement for two channels is satisfied by the Containment Air Particulate Monitor (R-41) and the Containment Radioactive Gas Monitor (R-42). Allowable values and setpoints for these Functions are based on engineering judgment.

Channel OPERABILITY involves more than OPERABILITY of the channel electronics. OPERABILITY may also require correct valve lineups, sample pump operation, and filter motor operation, as well as detector OPERABILITY, if these supporting features are necessary for trip to occur under the conditions assumed by the safety analyses.

3. Containment Isolation - Phase A

Refer to LCO 3.3.2, Function 3.a., for all initiating Functions and requirements. This Function is required only when the associated LCO 3.3.2, "ESFAS Instrumentation," function is required to be OPERABLE.

4. Containment Spray

Refer to LCO 3.3.2, "ESFAS Instrumentation," Function 2, for all initiation functions and requirements. This Function is required only when the associated LCO 3.3.2, "ESFAS Instrumentation," function is required to be OPERABLE.

APPLICABILITY

In MODES 1, 2, 3 or 4, isolation instrumentation for the containment purge supply line, containment purge exhaust line and the containment pressure relief line automatic isolation capability is not required if the associated flow paths are isolated in accordance with the requirements of LCO 3.6.3, "Containment Isolation Valves". If the associated flow paths are open in accordance with Surveillance Requirements 3.6.3.1 or 3.6.3.2, automatic isolation Function 1, Automatic Actuation Logic and Actuation Relays, and Function 3, Containment Isolation - Phase A, and Function 4, Containment Spray, are required as part of the containment isolation function initiated by the ESFAS Instrumentation required by LCO 3.3.2. Function 2.a,

BASES

APPLICABILITY (continued)

Containment Radioactive Gaseous Monitor (R-42), and Function 2.b, Containment Air Particulate Monitor (R-41), are required to be OPERABLE to provide an isolation signal that is diverse to the ESFAS isolation signals.

The Applicability for the containment purge system and pressure relief line isolation on the ESFAS Containment Isolation-Phase A and Containment Spray Functions are specified in LCO 3.3.2. Refer to the Bases for LCO 3.3.2 for discussion of the Containment Isolation-Phase A and Containment Spray Function Applicability.

In MODES 5 and 6, without fuel handling in progress or after 100 hours since reactor shutdown, isolation instrumentation for the containment purge supply line, containment purge exhaust line and the containment pressure relief line need not be OPERABLE because the potential for radioactive releases is minimized and operator action is sufficient to ensure post accident offsite doses are maintained within the limits of Reference 1.

During movement of recently irradiated fuel (i.e., fuel assemblies that have been part of a critical reactor in the previous 100 hours), the relaxations justified in Reference 2 do not apply. Therefore, LCO 3.3.6, "Containment Purge System and Pressure Relief Line Isolation Instrumentation," requirements are applicable during the movement of recently irradiated fuel.

ACTIONS

The most common cause of channel inoperability is outright failure or drift of the bistable or process module sufficient to exceed the tolerance allowed by unit specific calibration procedures. Typically, the drift is found to be small and results in a delay of actuation rather than a total loss of function. This determination is generally made during the performance of a COT, when the process instrumentation is set up for adjustment to bring it within specification. If the Trip Setpoint is less conservative than the tolerance specified by the calibration procedure, the channel must be declared inoperable immediately and the appropriate Condition entered.

A Note has been added to the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed in Table 3.3.6-1. The Completion Time(s) of the inoperable channel(s)/train(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

BASES

ACTIONS (continued)

A.1

Condition A applies to the failure of one containment purge isolation radiation monitor channel (either R-41 or R-42). Since the two containment radiation monitors measure different parameters, failure of a single channel may result in loss of the radiation monitoring Function for certain events. Consequently, the failed channel must be restored to OPERABLE status. A Completion Time of 7 days is allowed to restore the affected channel because the accident analysis assumes that an ESFAS SI signal isolates the containment vent paths. Therefore, the containment radiation monitoring function is not the primary method of ensuring that 10 CFR 50.67 limits are not exceeded.

B.1

Condition B applies to all Containment Purge System and Pressure Relief Line Isolation Functions and addresses the train orientation use of master relays for these Functions. It also addresses the failure of both radiation monitoring channels, or the inability to restore a single failed channel to OPERABLE status in the time allowed for Required Action A.1.

If a train is inoperable, multiple channels are inoperable, or the Required Action and associated Completion Time of Condition A are not met, operation may continue as long as the Required Action for the applicable Conditions of LCO 3.6.3 is met for each valve made inoperable by failure of isolation instrumentation.

A Note is added stating that Condition B is only applicable in MODE 1, 2, 3 or 4.

C.1 and C.2

Condition C applies to all Containment Purge System and Pressure Relief Line Isolation Functions. It also addresses the failure of multiple radiation monitoring channels, or the inability to restore a single failed channel to OPERABLE status in the time allowed for Required Action A.1. If a train is inoperable, multiple channels are inoperable, or the Required Action and associated Completion Time of Condition A are not met, operation may continue as long as the Required Action to place and maintain containment purge system and pressure relief line isolation valves in their closed position is met or the applicable Conditions of LCO 3.9.3, "Containment Penetrations," are met for each valve made inoperable by failure of isolation

BASES

ACTIONS (continued)

instrumentation. The Completion Time for these Required Actions is immediately.

A Note states that Condition C is applicable during movement of recently irradiated fuel assemblies within containment.

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that Table 3.3.6-1 determines which SRs apply to which Containment Purge and Exhaust Isolation Functions.

SR 3.3.6.1

Performance of the CHANNEL CHECK once every 24 hours ensures that a gross failure of instrumentation has not occurred and is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit. A CHANNEL CHECK for a single channel instrument is satisfied by verification that the sensor or the signal processing equipment has not drifted outside its limit.

The Frequency is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the LCO required channels.

SR 3.3.6.2

SR 3.3.6.2 is the performance of an ACTUATION LOGIC TEST. This test is performed every 31 days on a STAGGERED TEST BASIS. The Surveillance interval is acceptable based on instrument reliability and industry operating experience.

SR 3.3.6.3

SR 3.3.6.3 is the performance of a MASTER RELAY TEST. The MASTER RELAY TEST is the energizing of the master relay and verifying contact operation. This test is performed every 31 days on a STAGGERED TEST

BASES

SURVEILLANCE REQUIREMENTS (continued)

BASIS. The Surveillance interval is acceptable based on instrument reliability and industry operating experience.

SR 3.3.6.4

A COT is performed every 31 days on each radiation monitoring channel to ensure the entire channel will perform the intended Function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL OPERATIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. This test verifies the capability of the instrumentation to provide the containment purge supply line, containment purge exhaust line and the containment pressure relief line isolation. The setpoint shall be left consistent with the current unit specific calibration procedure tolerance.

SR 3.3.6.5

SR 3.3.6.5 is the performance of a TADOT. This test is a check performed every 24 months that verifies actuation of the end device (i.e., valve cycles, etc.).

The test also includes trip devices that provide actuation signals directly to the actuation relays, bypassing the analog process control equipment. The SR is modified by a Note that excludes verification of setpoints during the TADOT. The Functions tested have no setpoints associated with them.

The Frequency is based on the known reliability of the Function and the redundancy available, and has been shown to be acceptable through operating experience.

SR 3.3.6.6

A CHANNEL CALIBRATION is performed every 24 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 a measured parameter within the necessary range and accuracy. Allowable values and setpoints for these Functions are based on engineering judgment.

3.3 INSTRUMENTATION

3.3.7 Control Room Ventilation System (CRVS) Actuation Instrumentation

LCO 3.3.7 The CRVS actuation instrumentation for each Function in Table 3.3.7-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3 and 4,
During movement of recently irradiated fuel assemblies.

ACTIONS

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

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. - NOTE - Only applicable in MODE 1, 2, 3 or 4. One or more Functions inoperable.	A.1	Place one CRVS train in pressurization mode.	72 hours
B. Required Action and associated Completion Time for Condition A not met.	B.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	B.2	Be in MODE 5.	36 hours
C. - NOTE - Only applicable during movement of recently irradiated fuel assemblies. One or more Functions inoperable.	C.1	Suspend movement of recently irradiated fuel assemblies.	Immediately

Table 3.3.7-1 (page 1 of 1)
CRVS Actuation Instrumentation

	FUNCTION	REQUIRED CHANNELS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUES
1.	Manual Initiation	1 train	SR 3.3.7.4	NA
2.	Control Building Air Intake Radiation (R-38-1)	1	SR 3.3.7.1 SR 3.3.7.2 SR 3.3.7.3 SR 3.3.7.5	≤ 0.75 mr
3.	Control Room Air Intake Radiation (R-38-2)	1	SR 3.3.7.1 SR 3.3.7.2 SR 3.3.7.3 SR 3.3.7.5	≤ 0.75 mr
4.	Safety Injection	Refer to LCO 3.3.2, "ESFAS Instrumentation," Function 1, for all initiation functions and requirements.		

B 3.3 INSTRUMENTATION

B 3.3.7 Control Room Ventilation System (CRVS) Actuation Instrumentation

BASES

BACKGROUND

The CRVS provides an enclosed control room environment from which the unit can be operated following an uncontrolled release of radioactivity. Upon receipt of an actuation signal, the CRVS initiates filtered pressurization of the control room. This system is described in the Bases for LCO 3.7.10, "Control Room Ventilation System."

The actuation instrumentation consists of control room radiation monitor (R-38-2) in the air intake to the control room and the control building radiation monitor (R-38-1). The control room operator can also align and start both CRVS trains manually using the CRVS mode switch. The CRVS is also actuated by a safety injection (SI) signal. The SI Function is discussed in LCO 3.3.2, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation."

APPLICABLE SAFETY ANALYSES

The control room must be kept habitable for the operators stationed there during accident recovery and post accident operations.

The CRVS acts to terminate the supply of unfiltered outside air to the control room and pressurize the control room. These actions are necessary to ensure the control room is kept habitable for the operators stationed there during accident recovery and post accident operations by minimizing the radiation exposure of control room personnel.

In MODES 1, 2, 3, and 4, the radiation monitors actuate CRVS as a backup to the SI signal actuation. This ensures initiation of the CRVS during a loss of coolant accident or steam generator tube rupture.

Radiological consequence analyses have been revised to demonstrate compliance with 10 CFR 50.67, Accident Source Term. 10 CFR 50.67 (Ref. 1) requires that accident analyses show adequate radiation protection is provided to permit access to and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem total effective dose equivalent for the duration of the accident (Ref. 2).

BASES

LCO (continued)

2. Control Building Air Intake Radiation Monitor (R-38-1)

   The LCO requires a Control Building Air Intake Radiation Monitor to ensure that the radiation monitoring instrumentation will initiate a control room isolation if isolation on an SI signal fails to occur.

3. Control Room Air Intake Radiation Monitor (R-38-2)

   The LCO requires a Control Room Air Intake Radiation Monitor to ensure that the radiation monitoring instrumentation will initiate a control room isolation if isolation on an SI signal fails to occur.

4. Safety Injection

   Refer to LCO 3.3.2, Function 1, for all initiating Functions and requirements.

APPLICABILITY

In MODES 1, 2, 3 and 4, automatic CRVS actuation is needed to demonstrate compliance with 10 CFR 50.67, Accident Source Term (Ref. 1). OPERABILITY of CRVS Isolation instrumentation ensures that exposures following each event analyzed for MODES 1, 2, 3 and 4 are significantly below the required limits (Ref. 2).

In MODES 5 and 6 without fuel handling in progress or after the reactor has been shutdown for more than 100 hours, automatic CRVS actuation need not be OPERABLE because the potential for radioactive releases is minimized and operator action is sufficient to ensure post accident control room doses are maintained within the limits of Reference 1.

During movement of recently irradiated fuel assemblies either in containment or the fuel handling building, automatic CRVS actuation must be OPERABLE to cope with the release from a fuel handling accident involving recently irradiated fuel. The CRVS is only required to be OPERABLE during fuel handling involving recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 100 hours), due to radioactive decay.

The Applicability for the CRVS actuation on the ESFAS Safety Injection Functions are specified in LCO 3.3.2. Refer to the Bases for LCO 3.3.2 for discussion of the Safety Injection Function Applicability.

BASES

ACTIONS

A Note has been added to the ACTIONS indicating that separate Condition entry is allowed for each Function. The Conditions of this Specification may be entered independently for each Function listed in Table 3.3.7-1 in the accompanying LCO. The Completion Time(s) of the inoperable channel(s)/train(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

A.1

Condition A applies if one or more functions in Table 3.3.7-1 are inoperable. If the automatic CRVS start signal from any Function is inoperable, 72 hours is allowed to restore the Function consistent with the limit of 72 hours for loss of CRVS Function allowed by LCO 3.7.10. If the channel/train cannot be restored to OPERABLE status, one CRVS train must be placed in the filtered pressurization mode of operation. This accomplishes the actuation instrumentation Function and places the unit in a conservative mode of operation.

A Note to Condition A clarifies that Required Action A.1 is applicable only in MODE 1, 2, 3 or 4.

B.1 and B.2

Condition B applies when the Required Action and associated Completion Time for Condition A have not been met and the unit is in MODE 1, 2, 3, or 4. The unit must be brought to a MODE in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

C.1

Condition C applies when one or more functions are not OPERABLE when recently irradiated fuel assemblies are being moved. Movement of recently irradiated fuel assemblies must be suspended immediately to reduce the risk of accidents that could require CRVS actuation.

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that Table 3.3.7-1 determines which SRs apply to which CRVS Actuation Functions.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.5 RCS Loops - MODE 3

LCO 3.4.5 Two RCS loops shall be OPERABLE and either:

a. Two RCS loops shall be in operation when the Rod Control System is capable of rod withdrawal or

b. One RCS loop shall be in operation when the Rod Control System is not capable of rod withdrawal.

- NOTE -

All reactor coolant pumps may be removed from operation for ≤ 1 hour per 8 hour period provided:

a. No operations are permitted that would cause introduction into the RCS of any coolant with a boron concentration less than that required to meet the SDM of LCO 3.1.1; and

b. Core outlet temperature is maintained at least 10°F below saturation temperature.

APPLICABILITY: MODE 3.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One required RCS loop inoperable.	A.1	Restore required RCS loop to OPERABLE status.	72 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1	Be in MODE 4.	12 hours
C. One required RCS loop not in operation with Rod Control System capable of rod withdrawal.	C.1 OR	Restore required RCS loop to operation.	1 hour

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.6 RCS Loops - MODE 4

LCO 3.4.6 Two loops consisting of any combination of RCS loops and residual heat removal (RHR) loops shall be OPERABLE, and one loop shall be in operation.

- NOTES -

1. All reactor coolant pumps (RCPs) and RHR pumps may be removed from operation for ≤ 1 hour per 8 hour period provided:

   a. No operations are permitted that would cause introduction into the RCS of any coolant with a boron concentration less than that required to meet the SDM of LCO 3.1.1, and

   b. Core outlet temperature is maintained at least 10°F below saturation temperature.

2. No RCP shall be started with any RCS cold leg temperature ≤ 280°F unless the requirements for RCP starting in LCO 3.4.12 are met.

APPLICABILITY: MODE 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required loop inoperable.	A.1 Initiate action to restore a second loop to OPERABLE status.	Immediately
	<u>AND</u>	
	A.2 - NOTE - Only required if RHR loop is OPERABLE. Be in MODE 5.	24 hours

BASES

LCO (continued)

flow to remove the decay heat from the core with forced circulation. An additional loop is required to be OPERABLE to provide redundancy for heat removal.

Note 1 permits all RCPs and RHR pumps to be removed from operation for ≤ 1 hour per 8 hour period. The purpose of the Note is to permit tests that are designed to validate various accident analyses values. One of the tests performed during the startup testing program is the validation of rod drop times during cold conditions, both with and without flow. The no flow test may be performed in MODE 3, 4, or 5 and requires that the pumps be stopped for a short period of time. The Note permits the stopping of the pumps in order to perform this test and validate the assumed analysis values. If changes are made to the RCS that would cause a change to the flow characteristics of the RCS, the input values must be revalidated by conducting the test again. The 1 hour time period is acceptable because operating experience has shown that boron stratification is not a problem during this short period with no forced flow.

Utilization of Note 1 is permitted provided the following conditions are met along with any other conditions imposed by maintenance or test procedures:

a. No operations are permitted that would dilute the RCS boron concentration with coolant with boron concentrations less than required to meet SDM of LCO 3.1.1, therefore maintaining the margin to criticality. Boron reduction with coolant at boron concentrations less than required to assure SDM is maintained is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation. This Note does not prohibit injection into the RCS of water with a boron concentration that is equal to or greater than the minimum boron concentration needed to meet the SDM requirement in LCO 3.1.1 even if the water being injected has a lower boron concentration than the water already in the RCS.

b. Core outlet temperature is maintained at least 10°F below saturation temperature, so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

Note 2 requires that the reactor coolant pump starting requirements of LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP)", must be met if RCS temperature is less than or equal to the LTOP Applicability temperature. This restraint is to prevent a low temperature overpressure event due to a thermal transient when an RCP is started.

BASES

BACKGROUND (continued)

When using SGs depending on natural circulation as the backup decay heat removal system in MODE 5, consideration should be given to the potential need for the following:

(1) the ability to pressurize and control pressure in the RCS;

(2) secondary side water level in the SG relied upon for decay heat removal,

(3) availability of a supply of feedwater, and

(4) availability of an auxiliary feedwater pump capable of injecting into the relied-upon SGs (Ref. 1).

During natural circulation, the SGs secondary side water may boil creating the need to release steam through the atmospheric relief valves or other openings that may exist during shutdown conditions. Therefore, consideration should be given to avoiding the potential for pressurization of the SGs secondary side. It is also important to note that during the decay heat removal using natural circulation, a MODE change (MODE 5 to MODE 4) could occur due to heat up of the RCS (Ref. 1).

APPLICABLE SAFETY ANALYSES

In MODE 5, RCS circulation is considered in the determination of the time available for mitigation of the accidental boron dilution event. The RHR loops provide this circulation.

RCS Loops - MODE 5 (Loops Filled) satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

LCO

The purpose of this LCO is to require that at least one of the RHR loops be OPERABLE and in operation with an additional RHR loop OPERABLE or two SGs with secondary side water level ≥ 0% narrow range. One RHR loop provides sufficient forced circulation to perform the safety functions of the reactor coolant under these conditions. An additional RHR loop is required to be OPERABLE to meet single failure considerations. However, if the standby RHR loop is not OPERABLE, an acceptable alternate method is two SGs with their secondary side water levels ≥ 0% narrow range. Should the operating RHR loop fail, the SGs could be used to remove the decay heat via natural circulation.

BASES

LCO (continued)

Note 1 permits all RHR pumps to be removed from operation for ≤ 1 hour per 8 hour period. The purpose of the Note is to permit tests designed to validate various accident analyses values. One of the tests performed during the startup testing program is the validation of rod drop times during cold conditions, both with and without flow. The no flow test may be performed in MODE 3, 4, or 5 and requires that the pumps be stopped for a short period of time. The Note permits stopping of the pumps in order to perform this test and validate the assumed analysis values. If changes are made to the RCS that would cause a change to the flow characteristics of the RCS, the input values must be revalidated by conducting the test again. The 1 hour time period is acceptable because operating experience has shown that boron stratification is not likely during this short period with no forced flow.

Utilization of Note 1 is permitted provided the following conditions are met, along with any other conditions imposed by test or maintenance procedures:

a. No operations are permitted that would dilute the RCS boron concentration with coolant with boron concentrations less than required to meet SDM of LCO 3.1.1, therefore maintaining the margin to criticality. Boron reduction with coolant at boron concentrations less than required to assure SDM is maintained is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation. This Note does not prohibit injection into the RCS of water with a boron concentration that is equal to or greater than the minimum boron concentration needed to meet the SDM requirement in LCO 3.1.1 even if the water being injected has a lower boron concentration than the water already in the RCS.

b. Core outlet temperature is maintained at least 10°F below saturation temperature, so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

Note 2 allows one RHR loop to be inoperable for a period of up to 2 hours, provided that the other RHR loop is OPERABLE and in operation. This permits periodic surveillance tests to be performed on the inoperable loop during the only time when such testing is safe and possible.

Note 3 requires that the reactor coolant pump starting requirements of LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP)," be met if RCS temperature is less than or equal to the LTOP Applicability temperature specified in LCO 3.4.12. This restriction is to prevent a low temperature overpressure event due to a thermal transient when an RCP is started.

BASES

LCO (continued)

Note 4 provides for an orderly transition from MODE 5 to MODE 4 during a planned heatup by permitting removal of RHR loops from operation when at least one RCS loop is in operation. This Note provides for the transition to MODE 4 where an RCS loop is permitted to be in operation and replaces the RCS circulation function provided by the RHR loops.

RHR pumps are OPERABLE if they are capable of being powered and are able to provide flow if required. An OPERABLE SG can perform as a heat sink via natural circulation when it has an adequate water level and is OPERABLE in accordance with the Steam Generator Tube Surveillance Program.

If the SGs being credited as the redundant method of decay heat removal depend on natural circulation (Ref. 1) for decay heat removal, the SGs are considered OPERABLE only if:

a. RCS loop and reactor pressure vessel filling and venting are complete; or,

b. RCS pressure has been maintained > 100 psig since the RCP associated with the SG has been operated (which ensures that the SG tubes are filled) or since the loop has been filled and vented.

APPLICABILITY

In MODE 5 with RCS loops filled, this LCO requires forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. One loop of RHR provides sufficient circulation for these purposes. However, one additional RHR loop is required to be OPERABLE, or the secondary side water level of at least two SGs is required to be ≥ 0% narrow range.

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops - MODES 1 and 2;"
LCO 3.4.5, "RCS Loops - MODE 3;"
LCO 3.4.6, "RCS Loops - MODE 4;"
LCO 3.4.8, "RCS Loops - MODE 5, Loops Not Filled;"
LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level" (MODE 6), and
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level" (MODE 6).

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. No required RHR loop OPERABLE. OR Required RHR loop not in operation.	B.1	Suspend operations that would cause introduction into the RCS of any coolant with a boron concentration less than that required to meet SDM of LCO 3.1.1.	Immediately
	AND		
	B.2	Initiate action to restore one RHR loop to OPERABLE status and operation.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.8.1	Verify required RHR loop is in operation.	12 hours
SR 3.4.8.2	- NOTE - Not required to be performed until 24 hours after a required pump is not in operation. Verify correct breaker alignment and indicated power are available to each required RHR pump.	7 days

BASES

BACKGROUND (continued)

Pressurizer heaters are powered from either the offsite source or the diesel generators (DGs) through the four 480 V vital buses as follows:

Safeguards Power Train 5A supports heater group 23 (485 kW);

Safeguards Power Train 6A supports heater group 24 (277 kW); and

Safeguards Power Train 2A/3A supports both:
heater group 21 from Bus 3A (554 kW); and
heater group 22 from Bus 2A (485 kW).

APPLICABLE SAFETY ANALYSES

In MODES 1, 2, and 3, the LCO requirement for a steam bubble is reflected implicitly in the accident analyses. For events that result in pressurizer insurge (e.g., loss of normal feedwater and the loss of load/turbine trip), the analyses assume that the limiting nominal value for the highest initial pressurizer level is 60.6%. This is an analytical limit and does not include an allowance for instrument error. For other events, the nominal value of pressurizer level is assumed because the pressurizer level is automatically controlled and the effect of initial pressurizer level on PCT is small (Ref. 1). Safety analyses performed for lower MODES are not limiting. All analyses performed from a critical reactor condition assume the existence of a steam bubble and saturated conditions in the pressurizer. In making this assumption, the analyses neglect the small fraction of noncondensible gases normally present.

Safety analyses presented in the UFSAR (Ref. 1) do not take credit for pressurizer heater operation; however, an implicit initial condition assumption of the safety analyses is that the RCS is operating at normal pressure.

The maximum pressurizer water level limit, which ensures that a steam bubble exists in the pressurizer, satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii). Although the heaters are not specifically used in accident analysis, the need to maintain subcooling in the long term during loss of offsite power, as indicated in NUREG-0737 (Ref. 2), is the reason for providing an LCO.

LCO

The LCO requires the pressurizer to be OPERABLE with the actual water level less than or equal to 60.6%. This maximum pressurizer level of 60.6% is the nominal level that is used as the analytical limit for the initial condition in the accident analysis. Pressurizer level indications in the control room are

BASES

LCO (continued)

averaged to come up with a value for comparison to the limit. An additional margin of approximately 5%, should be allowed for instrument error (i.e., the indicated level should not exceed 55.6%).

Limiting the LCO maximum operating water level preserves the steam space for pressure control. The LCO has been established to ensure the capability to establish and maintain pressure control for steady state operation and to minimize the consequences of potential overpressure transients. Requiring the presence of a steam bubble is also consistent with analytical assumptions.

The LCO requires two groups of OPERABLE pressurizer heaters, each with a capacity ≥ 150 kW. Each of the two groups of pressurizer heaters must be powered from a different DG to ensure that the minimum required capacity of 150 kW can be energized during a loss of offsite power condition assuming the failure of a single DG. The minimum heater capacity required is sufficient to maintain the RCS near normal operating pressure when accounting for heat losses through the pressurizer insulation. By maintaining the pressure near the operating conditions, a wide margin to subcooling can be obtained in the loops. The value of 150 kW has been demonstrated to be adequate to maintain RCS pressures control.

APPLICABILITY

The need for pressure control is most pertinent when core heat can cause the greatest effect on RCS temperature, resulting in the greatest effect on pressurizer level and RCS pressure control. Thus, applicability has been designated for MODES 1 and 2. The applicability is also provided for MODE 3. The purpose is to prevent solid water RCS operation during heatup and cooldown to avoid rapid pressure rises caused by normal operational perturbation, such as reactor coolant pump startup.

In MODES 1, 2, and 3, there is need to maintain the availability of pressurizer heaters, capable of being powered from an emergency power supply. In the event of a loss of offsite power, the initial conditions of these MODES give the greatest demand for maintaining the RCS in a hot pressurized condition with loop subcooling for an extended period. For MODE 4, 5, or 6, it is not necessary to control pressure (by heaters) to ensure loop subcooling for heat transfer when the Residual Heat Removal (RHR) System is in service, and therefore, the LCO is not applicable.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.12 Low Temperature Overpressure Protection (LTOP)

LCO 3.4.12

LTOP shall be OPERABLE in accordance with one of the options in Table 3.4.12-1 and the accumulators shall be isolated.

- NOTES -

1. Accumulator isolation is only required when accumulator pressure is greater than or equal to the maximum RCS pressure for the coldest existing RCS cold leg temperature allowed by the P/T limit curves provided in Figure 3.4.12-1.

2. If conditions require the use of High Head Safety Injection (HHSI) pumps in the event of loss of RCS inventory, the pumps can be made capable of injecting into the RCS.

3. One HHSI pump may be made capable of injecting into the RCS as needed to support abnormal operations such as emergency boration or response to loss of RHR cooling.

4. SR 3.4.12.8 shall be met prior to starting a reactor coolant pump (RCP) if no other RCPs are in operation.

APPLICABILITY:

MODE 4 when any RCS cold leg temperature is ≤ 280°F,
MODE 5,
MODE 6 when the reactor vessel head is on.

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.4.12.1	- NOTE - Not required to be met when Table 3.4.12-1, Option I, is met. Verify that the number of HHSI pumps and charging pumps capable of injecting into the RCS is within Table 3.4.12-1 limits for plant conditions.	12 hours for pumps with circuit breakers not locked out <u>AND</u> 31 days for pumps with circuit breakers locked out
SR 3.4.12.2	- NOTE - Not required to be met when Table 3.4.12-1, Option A, B, F, G, H or I is met. Verify that the combination of pressurizer pressure, pressurizer level and RCS temperature is within the limits of the Figure specified in Table 3.4.12-1 for the number of HHSI pumps and charging pumps capable of injecting into the RCS.	12 hours
SR 3.4.12.3	Verify each accumulator discharge isolation valve is closed and power removed. <u>OR</u> Verify each accumulator pressure is less than the maximum RCS pressure allowed by the P/T limit curves in Figure 3.4.12-1 for the coldest existing RCS cold leg temperature.	12 hours 12 hours

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.12 Low Temperature Overpressure Protection (LTOP)

BASES

BACKGROUND

LTOP is the combination of restrictions on RCS injection capability, RCS relief capacity or vent size, and reactor coolant pump starting restrictions that limit RCS pressure at low temperatures. The LTOP restrictions ensure the integrity of the reactor coolant pressure boundary (RCPB) is not compromised by violating the pressure and temperature (P/T) limits of 10 CFR 50, Appendix G as described in Reference 1. The reactor vessel is the limiting RCPB component for demonstrating such protection. This LCO provides the maximum allowable actuation logic setpoints for the power operated relief valves (PORVs) and the maximum RCS pressure for the existing RCS cold leg temperature during cooldown, shutdown, and heatup to meet the Reference 1 requirements during the LTOP MODES.

The reactor vessel material is less tough at low temperatures than at normal operating temperature. As the vessel neutron exposure accumulates, the material toughness decreases and becomes less resistant to pressure stress at low temperatures (Ref. 2). RCS pressure, therefore, is maintained low at low temperatures and is increased only as temperature is increased.

The potential for vessel overpressurization is most acute when the RCS is water solid, which occurs only while shutdown. In a solid condition, a pressure fluctuation can occur more quickly than an operator can react to relieve the condition. Exceeding the RCS P/T limits by a significant amount could cause brittle cracking of the reactor vessel. LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits," requires administrative control of RCS pressure and temperature during heatup and cooldown to prevent exceeding the Reference 1 limits.

This LCO provides RCS overpressure protection by a combination of limiting RCS injection capability of the high head safety injection (HHSI) pumps and the charging pumps based on the pressure relief capability provided by the Overpressure Protection System (OPS) (i.e., redundant power operated relief valves with setpoints based on the RCS temperature) or the size of the vent provided in the RCS for pressure relief. Alternately, if redundant PORVs are not OPERABLE or an RCS vent cannot be established, LTOP protection may be established by limiting the pressurizer level to within limits specified in Figure 3.4.12-2, Figure 3.4.12-3, or Figure 3.4.12-4 consistent with the number of charging pumps and number of HHSI pumps capable of injecting into the RCS. This approach is acceptable because pressurizer level can be maintained such that it will either accommodate any anticipated

BASES

BACKGROUND (continued)

valves when RCS temperature falls below the temperature at which low temperature overpressure protection is required; and, b) provide an open permissive in a two-out-of-two (temperature and pressure) logic for each PORV. When the PORV block valves are open (either manually or as a result of the signal from RCS cold leg temperature) and temperature requirement for PORV opening is met, the PORVs are said to be "armed."

Three channels of RCS pressure are used in a two-out-of-three logic to satisfy the pressure portion of the two-out-of-two (temperature-pressure) logic that actuates each PORV in the overpressure protection mode of operation.

Having the pressure/temperature setpoint of both PORVs within the limits in Figure 3.4.12-1 ensures that the Reference 1 limits will not be exceeded in any analyzed event. Use of two PORVs, each with adequate relieving capability to prevent overpressurization, ensures that a single failure will not prevent PORV actuation. Use of a two-out-of-three logic for pressure and for temperature ensures that a single failure will not cause or prevent a PORV actuation when in the overpressure protection mode of operation.

When a PORV is opened during an increasing pressure transient, the release of coolant will cause the pressure increase to slow and reverse. As the PORV releases coolant, the RCS pressure decreases until a reset pressure is reached and the valve is signaled to close. The pressure continues to decrease below the reset pressure as the valve closes.

RCS Vent Requirements

When the RCS is depressurized, a vent exposed to the containment atmosphere will maintain the RCS at containment ambient pressure in an RCS overpressure transient, if the relieving requirements of the transient do not exceed the capabilities of the vent. Thus, the vent path must be capable of relieving the flow resulting from the limiting LTOP mass or heat input transient, and maintaining pressure below the P/T limits. The required vent capacity may be provided by one or more vent paths.

Depending on the required vent size, RCS vent flow capacity requirements may be met by removing a pressurizer safety valve, blocking open the PORV and disabling its block valve in the open position, removing a PORV's internals, and disabling its block valve in the open position, establishing a vent by opening an RCS vent valve or by removing the pressurizer manway cover. The vent path(s) must be above the level of reactor coolant, so as not to drain the RCS when open.

BASES

APPLICABLE SAFETY ANALYSES

Safety analyses (Ref. 4) demonstrate that the reactor vessel is adequately protected against exceeding the Reference 1 P/T limits. In MODES 1, 2, and 3, and in MODE 4 with all RCS cold leg temperatures exceeding 280°F, the pressurizer safety valves will prevent RCS pressure from exceeding the Reference1 limits. At about 280°F and below, overpressure protection is established by restricting RCS injection capability using the HHSI pumps and the charging pumps based on the pressure relief capability provided by one of the two power operated relief valves with setpoints based on the RCS temperature (i.e., the Overpressure Protection System) or the size of the vent provided in the RCS for pressure relief. Alternately, if redundant PORVs are not OPERABLE or an RCS vent cannot be established, LTOP protection may be established by limiting the pressurizer level to within limits specified in Figure 3.4.12-2, Figure 3.4.12-3, or Figure 3.4.12-4 depending on the number of charging pumps and number of HHSI pumps capable of injecting into the RCS. This approach is acceptable because pressurizer level can be maintained such that it will either accommodate any anticipated pressure surge or allow operators time to react to any unanticipated pressure surge. When pressurizer level is used to satisfy LTOP requirements, operator action is assumed to terminate an unplanned HHSI pump injection within 10 minutes. The LTOP analysis also assumes that the RCS accumulators are either isolated or depressurized whenever LTOP requirements are applicable.

The actual temperature at which the pressure in the P/T limit curve falls below the pressurizer safety valve setpoint increases as the reactor vessel material toughness decreases due to neutron embrittlement. Each time the P/T curves are revised, LTOP must be re-evaluated to ensure its functional requirements can still be met using the RCS relief valve method or the depressurized and vented RCS condition.

Table 3.4.12-1 and Figures 3.4.12-1 through 3.4.12-6 contain the acceptance limits that define the LTOP requirements. Any change to the RCS must be evaluated against the Reference 4 analyses to determine the impact of the change on the LTOP acceptance limits.

Transients that are capable of overpressurizing the RCS are categorized as either mass or heat input transients, examples of which follow:

<u>Mass Input Type Transients</u>

a. Inadvertent safety injection or

b. Charging/letdown flow mismatch.

BASES

LCO (continued)

Options C, D or E are used only when the required PORVs in OPS mode are not OPERABLE and there is no vent path established. These options depend on maintaining the combination of pressurizer pressure, pressurizer level and RCS temperature within the limits specified in Figure 3.4.12-2, Figure 3.4.12-3, or Figure 3.4.12-4 depending on the number of HHSI pumps and charging pumps capable of injecting into the RCS.

Options F, G, H and I satisfy LTOP requirements when the RCS is depressurized and an RCS vent of the required size is maintained. A fully blocked open PORV or a PORV with the internals removed with the associated block valve blocked open establishes a vent path ≥ 2.00 square inches. Other methods for establishing a vent of the required size are also acceptable.

Each of these methods of overpressure prevention is capable of mitigating the limiting LTOP transient.

The LCO is modified by four Notes. Note 1 states that accumulator isolation (i.e., valve closed and power removed as specified in SR 3.4.12.3) is only required when the accumulator pressure is more than or at the maximum RCS pressure for the coldest existing temperature, as allowed by the P/T limit curves. This note permits the accumulator discharge isolation valve Surveillance to be performed only under these pressure and temperature conditions.

Note 2 allows the HHSI pumps to be made capable of injecting into the RCS if required to respond to a loss of RCS inventory. Note 3 allows one HHSI pump to be made capable of injecting into the RCS as needed for emergency boration or in response to loss of RHR cooling. Note 4 specifies that SR 3.4.12.8 must be met when starting any RCP to ensure that temperature asymmetry within the RCS or between the RCS and steam generators does not result in a pressure increase that could exceed LTOP relief capacity.

APPLICABILITY

This LCO is applicable in MODE 4 when any RCS cold leg temperature is ≤ 280°F, in MODE 5, and in MODE 6 when the reactor vessel head is on. The pressurizer safety valves provide overpressure protection that meets the Reference 1 P/T limits above 280°F. When the reactor vessel head is off, overpressurization cannot occur.

BASES

ACTIONS (continued)

E.1

The RCS must be depressurized and a vent must be established within 8 hours when:

a. Both required PORVs are inoperable,

b. A Required Action and associated Completion Time of Condition A or D is not met, or

c. LTOP is inoperable for any reason other than Condition A, B, C or D.

The vent must be consistent with Table 3.4.12-1, Options F, G, H or I, to ensure that the flow capacity is greater than that required for the worst case mass input transient reasonable during the applicable MODES. This action is needed to protect the RCPB from a low temperature overpressure event and a possible brittle failure of the reactor vessel.

Required Action E.1 requires that injection capability be limited in accordance with Table 3.4.12-1 for existing plant conditions to minimize the potential for an overpressure event while the plant is being depressurized and a vent path established.

The Completion Time of 8 hours for depressurizing and establishing the vent required by Table 3.4.12-1 considers the time required to place the plant in this Condition and the relatively low probability of an overpressure event during this time period due to increased operator awareness of administrative control requirements.

SURVEILLANCE REQUIREMENTS

SR 3.4.12.1, SR 3.4.12.2, and SR 3.4.12.3

To minimize the potential for a low temperature overpressure event by limiting the mass input capability, any HHSI or charging pump above the specified limit is verified incapable of injecting into the RCS and the accumulator discharge isolation valves are verified closed and locked out. The HHSI pumps and charging pumps are rendered incapable of injecting into the RCS through removing the power from the pumps by racking the breakers out under administrative control. An alternate method of LTOP control may be employed using at least two independent means to prevent a pump start such that a single failure or single action will not result in an

BASES

SURVEILLANCE REQUIREMENTS (continued)

injection into the RCS. This may be accomplished through the pump control switch being placed in pull to lock and at least one valve in the discharge flow path being closed.

The Frequency of 12 hours (and 31 days for pumps with circuit breakers locked out) is sufficient, considering other indications and alarms available to the operator in the control room, to verify the required status of the equipment. SR 3.4.12.1 is modified by a Note that permits not performing the required verification that the number of HHSI pumps and charging pumps capable of injecting into the RCS is within Table 3.4.12-1 limits when Option I is met. This is acceptable because Table 3.4.12-1, Option I, does not impose any limitations on the status of HHSI pumps and charging pumps.

SR 3.4.12.2 is modified by a Note that permits not performing the required verification that pressurizer pressure, pressurizer level and RCS temperature are within limits for the number of HHSI pumps and charging pumps capable of injecting into the RCS unless when Table 3.4.12-1, Option A, B, F, G, H or I, is being used to meet LTOP requirements. This is acceptable because these options do not impose any restrictions on the combination of pressurizer pressure, pressurizer level and RCS temperature.

SR 3.4.12.4

The RCS vent ≥ 2.00 or ≥ 5.00 square inches is proven OPERABLE by verifying its open condition either:

a. Once every 24 hours for a valve that is not locked (valves that are sealed or secured in the open position are considered "locked" in this context) or

b. Once every 31 days for other vent path(s) (e.g., a vent valve that is locked, sealed, or secured in position or a removed PORV (for a vent ≥ 2.00 square inches per PORV) or a pressurizer safety valve (for a vent ≥ 5.00 square inches) or open manway also fits this category).

The passive vent path arrangement must only be open to be OPERABLE. This Surveillance is required to be met if the vent is being used to satisfy the pressure relief requirements of Table 3.4.12-1, Options F through I.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.12.5

The PORV block valve must be verified open every 72 hours to provide the flow path for each required PORV to perform its function when actuated. The valve must be remotely verified open in the main control room. This Surveillance is performed only if the PORV is being used to satisfy the LCO.

The block valve is a remotely controlled, motor operated valve that opens automatically below the LTOP Applicability temperature. The power to the valve operator is not required to be removed, and the manual operator is not required to be locked in the open position. Thus, the block valve can be closed in the event the PORV develops excessive leakage or does not close (sticks open) after relieving an overpressure situation.

The 72 hour Frequency is considered adequate in view of other administrative controls available to the operator in the control room, such as valve position indication, that verify that the PORV block valve remains open.

SR 3.4.12.6

Performance of a COT on each required PORV is required within 12 hours after decreasing RCS temperature to less than or equal to LTOP Applicability temperature and every 31 days thereafter to verify and, as necessary, adjust its lift setpoint. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable COT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. The COT will verify the setpoint is within Figure 3.4.12-1 allowed maximum limits. PORV actuation could depressurize the RCS and is not required.

A Note has been added indicating that this SR is required to be performed (i.e., completed) within 12 hours after decreasing RCS cold leg temperature to ≤ 280°F. The 12 hour allowance considers the unlikelihood of a low temperature overpressure event during this time.

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.4.13.1	- NOTE - Not required to be performed in MODE 3 or 4 until 12 hours of steady state operation. Verify RCS Operational LEAKAGE is within limits by performance of RCS water inventory balance.	72 hours
SR 3.4.13.2	Verify steam generator tube integrity is in accordance with the Steam Generator Tube Surveillance Program.	In accordance with the Steam Generator Tube Surveillance Program

BASES

APPLICABLE SAFETY ANALYSES (continued)

The RCS operational LEAKAGE satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

RCS operational LEAKAGE shall be limited to:

a. Pressure Boundary LEAKAGE

No pressure boundary LEAKAGE is allowed, being indicative of material deterioration. LEAKAGE of this type is unacceptable as the leak itself could cause further deterioration, resulting in higher LEAKAGE. Violation of this LCO could result in continued degradation of the RCPB. LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE.

b. Unidentified LEAKAGE

One gallon per minute (gpm) of unidentified LEAKAGE is allowed as a reasonable minimum detectable amount that the containment air monitoring and containment sump level monitoring equipment can detect within a reasonable time period. Violation of this LCO could result in continued degradation of the RCPB, if the LEAKAGE is from the pressure boundary.

c. Identified LEAKAGE

Up to 10 gpm of identified LEAKAGE is considered allowable because LEAKAGE is from known sources that do not interfere with detection of unidentified LEAKAGE and is well within the capability of the RCS Makeup System. Identified LEAKAGE includes LEAKAGE to the containment from specifically known and located sources, but does not include pressure boundary LEAKAGE or controlled reactor coolant pump (RCP) seal leakoff (a normal function not considered LEAKAGE). Violation of this LCO could result in continued degradation of a component or system.

d. Primary to Secondary LEAKAGE through Any One SG

The 150 gpd (0.1 gpm) limit for primary to secondary LEAKAGE in each of the four SGs is part of the performance criteria for the SG tube surveillance program required by Technical Specification 5.5.7, Steam Generator (SG) Tube Surveillance Program, and Reference 6. SG leakage monitoring and the associated limit allows operators to safely

BASES

LCO (continued)

respond to situations in which tube integrity becomes impaired before significant leakage or tube failure occurs.

Note that primary to secondary LEAKAGE is also counted as identified LEAKAGE in accordance with Technical Specification 1.1, "Definitions."

APPLICABILITY

In MODES 1, 2, 3, and 4, the potential for RCPB LEAKAGE is greatest when the RCS is pressurized.

In MODES 5 and 6, LEAKAGE limits are not required because the reactor coolant pressure is far lower, resulting in lower stresses and reduced potentials for LEAKAGE.

LCO 3.4.14, "RCS Pressure Isolation Valve (PIV) Leakage," measures leakage through each individual PIV and can impact this LCO. Of the two PIVs in series in each isolated line, leakage measured through one PIV does not result in RCS LEAKAGE when the other is leak tight. If both valves leak and result in a loss of mass from the RCS, the loss must be included in the allowable identified LEAKAGE.

ACTIONS

A.1

Unidentified LEAKAGE, identified LEAKAGE, or primary to secondary LEAKAGE in excess of the LCO limits must be reduced to within limits within 4 hours. This Completion Time allows time to verify leakage rates and either identify unidentified LEAKAGE or reduce LEAKAGE to within limits before the reactor must be shut down. This action is necessary to prevent further deterioration of the RCPB.

B.1 and B.2

If any pressure boundary LEAKAGE exists, or if unidentified LEAKAGE, identified LEAKAGE, or primary to secondary LEAKAGE cannot be reduced to within limits within 4 hours, the reactor must be brought to lower pressure conditions to reduce the severity of the LEAKAGE and its potential consequences. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. The reactor must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours. This action reduces the LEAKAGE and also reduces the factors that tend to degrade the pressure boundary.

BASES

LCO (continued)

The LCO PIV leakage limit is a maximum limit of 5 gpm. However, if the leakage is greater than 1.0 gpm and the leak test indicates that there is significant deterioration from the previous leak test, then the results are unacceptable because of the adverse trend. Significant deterioration is indicated when the leakage is greater than the results of the previous test plus one-half of the margin following the previous test (i.e., margin following previous test is the 5.0 gpm limit minus the results of the previous test).

Leakage limit acceptance criteria is based on the leakage rate that would exist when the RCS is at normal operating pressure (i.e., ≥ 2215 psig and ≤ 2255 psig). Reference 7 permits leakage testing at a lower pressure differential than between the specified maximum RCS pressure and the normal pressure of the connected system during RCS operation (the maximum pressure differential) in those types of valves in which the higher service pressure will tend to diminish the overall leakage channel opening. In such cases, the observed rate may be adjusted to the maximum pressure differential by assuming leakage is directly proportional to the pressure differential to the one-half power. Minimum test differential pressure is 150 psid. Leakage may be measured indirectly (as from the performance of pressure indicators) if accomplished in accordance with approved procedures and supported by computations showing the method is capable of demonstrating valve compliance with the leakage criteria.

This LCO also requires that RCS boundary valves 730 and 731 are closed and de-energized within 24 hours after securing from use of the RHR in decay heat removal mode.

APPLICABILITY

In MODES 1, 2, 3, and 4, this LCO applies because the PIV leakage potential is greatest when the RCS is pressurized. In MODE 4, valves in the RHR flow path are not required to meet the requirements of this LCO when in, or during the transition to or from, the RHR mode of operation.

In MODES 5 and 6, leakage limits are not provided because the lower reactor coolant pressure results in a reduced potential for leakage and for a LOCA outside the containment.

BASES

LCO (continued)

high degree of confidence that extremely small leaks are detected in time to allow actions to place the plant in a safe condition, when RCS LEAKAGE indicates possible RCPB degradation.

The LCO is satisfied when monitors of diverse measurement means are available. Thus, the containment sump monitor, in combination with a gaseous or particulate radioactivity monitor and the containment fan cooler condensate flow rate monitor, provides an acceptable minimum.

The following instruments may be used to satisfy requirements for diverse RCS leakage monitoring requirements:

a. Requirement for one containment sump (level or discharge flow) monitor may be satisfied by any one of the following instruments:

    LT-940, LT-941, LT-3300, LT-3303, LT-3304 if a containment sump level instrument is used to meet this requirement; or

    FIT-3401 if containment sump discharge flow is used to meet this requirement.

b. Requirement for one containment atmosphere radioactivity monitor (gaseous or particulate) may be satisfied by either R-41, Containment Air Particulate Monitor, or R-42, Containment Air Gaseous Monitor. Note that either FCU 22 or FCU 25 should be in operation to provide representative sampling to the R-41 and R-42 Radiation Monitors. If neither FCU 22 or FCU 25 are in operation, plant operating procedures provide direction for use of temporary sampling hoses that may be used to ensure R-41 and R-42 receive representative samples.

c. Requirement for one containment fan cooler condensate flow rate monitor is satisfied by one condensate flow monitor associated with any FCU with fan in operation and cooling water flow through the unit.

APPLICABILITY

Because of elevated RCS temperature and pressure in MODES 1, 2, 3, and 4, RCS leakage detection instrumentation is required to be OPERABLE.

In MODE 5 or 6, the temperature is to be ≤ 200°F and pressure is maintained low or at atmospheric pressure. Since the temperatures and pressures are far lower than those for MODES 1, 2, 3, and 4, the likelihood of leakage and crack propagation are much smaller. Therefore, the requirements of this LCO are not applicable in MODES 5 and 6.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.16 RCS Specific Activity

LCO 3.4.16 The specific activity of the reactor coolant shall be within limits.

APPLICABILITY: MODES 1 and 2,
MODE 3 with RCS average temperature (T_{avg}) ≥ 500°F.

ACTIONS

CONDITION		REQUIRED ACTION	COMPLETION TIME
A. DOSE EQUIVALENT I-131 > 1.0 μCi/gm.		- NOTE - LCO 3.0.4.c is applicable.	
	A.1	Verify DOSE EQUIVALENT I-131 is ≤ 60.0 μCi/gm.	Once per 4 hours
	AND		
	A.2	Restore DOSE EQUIVALENT I-131 to within limit.	48 hours
B. Gross specific activity of the reactor coolant not within limit.	B.1	Be in MODE 3 with T_{avg} < 500°F.	6 hours
C. Required Action and associated Completion Time of Condition A not met. OR DOSE EQUIVALENT I-131 > 60.0 μCi/gm.	C.1	Be in MODE 3 with T_{avg} < 500°F.	6 hours

BASES

APPLICABILITY (continued)

In MODE 3, with RCS pressure ≤ 1000 psig, and in MODES 4, 5, and 6, the accumulator motor operated isolation valves are closed to isolate the accumulators from the RCS. This allows RCS cooldown and depressurization without discharging the accumulators into the RCS or requiring depressurization of the accumulators.

ACTIONS

A.1

If the boron concentration of one accumulator is not within limits of SR 3.5.1.4, it must be returned to within the limits within 72 hours. In this Condition, ability to maintain subcriticality or minimum boron precipitation time may be reduced. The boron in the accumulators contributes to the assumption that the combined ECCS water in the partially recovered core during the early reflooding phase of a large break LOCA is sufficient to keep that portion of the core subcritical. One accumulator below the minimum boron concentration limit, however, will have no effect on available ECCS water and an insignificant effect on core subcriticality during reflood. Boiling of ECCS water in the core during reflood concentrates boron in the saturated liquid that remains in the core. In addition, current analysis techniques demonstrate that the accumulators do not discharge following a large main steam line break for the majority of plants. Even if they do discharge, their impact is minor and not a design limiting event. Thus, 72 hours is allowed to return the boron concentration to within limits.

B.1

If one accumulator is inoperable for a reason other than boron concentration, the accumulator must be returned to OPERABLE status within 24 hours. In this Condition, the required contents of three accumulators cannot be assumed to reach the core during a LOCA. Due to the severity of the consequences should a LOCA occur in these conditions, the 24 hour Completion Time to open the valve, remove power to the valve, or restore the proper water volume or nitrogen cover pressure ensures that prompt action will be taken to return the inoperable accumulator to OPERABLE status. The Completion Time minimizes the potential for exposure of the plant to a LOCA under these conditions. The 24 hours allowed to restore an inoperable accumulator to OPERABLE status is justified in WCAP-15049, Rev. 1 (Ref. 4).

BASES

BACKGROUND (continued)

RCS cold legs will place the plant outside the design bases. Therefore, flow through both ECCS injection flow paths is required to satisfy the ECCS safety function of the Recirculation System (i.e., both flow paths are required to support OPERABILITY of the ECCS function of either of the Containment Recirculation System pumps).

The three ECCS systems (3 HHSI, 2 RHR and 2 Recirculation) are grouped into three trains (5A, 2A/3A and 6A) such that any 2 of the 3 trains are capable of meeting all ECCS capability assumed in the accident analysis. Each ECCS train consists of the following:

a. ECCS Train 5A includes subsystems HHSI 21 and containment recirculation 21;

b. ECCS Train 2A/3A includes subsystems HHSI 22 and RHR 21; and,

c. ECCS Train 6A includes subsystems HHSI 23, RHR 22, and containment recirculation 22.

The ECCS trains use the same designation as the Safeguards Power Trains required by LCO 3.8.9, Distribution Systems - Operating, with Safeguards Power Train 5A supported by DG 21, Safeguards Power Train 2A/3A supported by DG 22, Safeguards Power Train 6A supported by DG 23.

The ECCS accumulators and the RWST are also part of the ECCS, but are not considered part of an ECCS flow path as described by this LCO.

Each of the subsystems (3 HHSI, 2 RHR and 2 Recirculation) are interconnected and redundant such that any combination of 2 HHSI pumps, 1 RHR pump and 1 recirculation pump is capable of supplying 100% of the flow required to mitigate the accident consequences. This interconnecting and redundant subsystem design provides the operators with the ability to utilize components from different trains to achieve the required 100% flow to the core. The design intent is that any two of the three safeguards power trains is capable of providing 100% of the required ECCS flow; however, any combination of the minimum number of pumps is capable of providing 100% of the required ECCS flow.

During the injection phase of LOCA recovery, a suction header supplies water from the RWST to the HHSI and RHR pumps. The discharge from the HHSI and RHR pumps divides and feeds an injection line to each of the RCS cold legs. Control valves are set to balance the HHSI flow to the RCS.

BASES

BACKGROUND (continued)

This balance ensures sufficient flow to the core to meet the analysis assumptions following a LOCA in one of the RCS cold legs. Additionally, orifices on the HHSI pump discharge prevent pump runout due to increased flow as the RCS depressurizes during an accident.

For LOCAs that are too small to depressurize the RCS below the shutoff head of the HHSI pumps, the charging pumps supply water until the RCS pressure decreases below the HHSI pump shutoff head. During this period, the steam generators are used to provide part of the core cooling function.

During the recirculation phase of LOCA recovery, the containment recirculation pumps take suction from the containment recirculation sump and direct flow through the RHR heat exchangers to the cold legs. The RHR pumps can also be used to provide a backup method of recirculation because the RHR pump suction is transferred to the containment sump. The RHR pumps then supply recirculation flow directly and can also supply the suction of the HHSI pumps. Initially, recirculation is through the same paths as the injection phase. Subsequently, recirculation alternates injection between the hot and cold legs.

The ECCS also functions to supply borated water to the reactor core following increased heat removal events, such as a main steam line break (MSLB). The limiting design conditions occur when the negative moderator temperature coefficient is highly negative, such as at the end of each cycle.

During low temperature conditions in the RCS, limitations are placed on the maximum number of HHSI pumps that may be capable of injecting into the RCS. Refer to the Bases for LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP)," for the basis of these requirements.

The ECCS subsystems, except for the containment recirculation subsystems, are actuated upon receipt of an SI signal. The actuation of safeguard loads is accomplished in a programmed time sequence. If offsite power is available, the safeguard loads start immediately in the programmed sequence. If offsite power is not available, the Engineered Safety Feature (ESF) buses shed normal operating loads and are connected to the emergency diesel generators (EDGs). Safeguard loads are then actuated in the programmed time sequence. The time delay associated with diesel starting, sequenced loading, and pump starting determines the time required before pumped flow is available to the core following a LOCA.

BASES

BACKGROUND (continued)

The active ECCS components, along with the passive accumulators and the RWST covered in LCO 3.5.1, "Accumulators," and LCO 3.5.4, "Refueling Water Storage Tank (RWST)," provide the cooling water necessary to meet GDC 35 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The LCO helps to ensure that the following acceptance criteria for the ECCS, established by 10 CFR 50.46 (Ref. 2), will be met following a LOCA:

a. Maximum fuel element cladding temperature is ≤ 2200°F,

b. Maximum cladding oxidation is ≤ 0.17 times the total cladding thickness before oxidation,

c. Maximum hydrogen generation from a zirconium water reaction is ≤ 0.01 times the hypothetical amount generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react,

d. Core is maintained in a coolable geometry, and

e. Adequate long term core cooling capability is maintained.

The LCO also limits the potential for a post trip return to power following an MSLB event and ensures that containment temperature limits are met.

Each ECCS subsystem is taken credit for in a large break LOCA event at full power (Refs. 3 and 4). This event establishes the requirement for runout flow for the ECCS pumps, as well as the maximum response time for their actuation. The HHSI pumps are credited in a small break LOCA event. The OPERABILITY requirements for the ECCS are based on the following LOCA analysis assumptions:

a. A large break LOCA event, with loss of offsite power and the loss of one of the three safeguards power trains is assumed for the determination of pumped Emergency Core Cooling System (ECCS) flow during the LOCA. However, all three safeguards power trains were assumed to operate in the calculation of containment backpressure. This will conservatively bound the possible single failures (UFSAR 14.3.3.2); and

BASES

LCO (continued)

either HHSI pump 21 or 23 is inoperable, HHSI pump 22 is OPERABLE if it will automatically align or is manually aligned to replace the inoperable HHSI pump. The ECCS analyses assume high head safety injection into all four RCS cold legs (including the faulted loop). The isolation of high head safety injection flow to any of the RCS cold legs will place the plant outside the design bases. Therefore, flow through both ECCS injection flow paths is required to satisfy the safety function of the high head safety injection system (i.e., both flow paths are required to support OPERABILITY of two or more HHSI pumps).

Each ECCS RHR subsystem consists of one RHR pump and one RHR heat exchanger as well as associated piping and valves to transfer water from the suction source to the core. Although either RHR heat exchanger may be credited for either RHR subsystem, one RHR heat exchanger must be OPERABLE for each OPERABLE RHR injection subsystem. The ECCS analyses assume RHR injection into all four RCS cold legs (including the faulted loop).

Each containment recirculation subsystem consists of one Containment Recirculation pump and one RHR heat exchanger as well as associated instrumentation, piping and valves to transfer water from the suction source to the core. Although either RHR heat exchanger may be credited for either Containment Recirculation subsystem, one RHR heat exchanger must be OPERABLE for each OPERABLE Containment Recirculation subsystem.

During an event requiring ECCS actuation, a flow path is required to provide an abundant supply of water from the RWST to the RCS via the HHSI and RHR pumps and their respective supply headers to each of the four cold leg injection nozzles. In the long term, this flow path may be switched to take its supply from the containment recirculation sump using the containment recirculation pumps or, alternately, the containment sump using the RHR pumps and to supply its flow to the RCS hot and cold legs.

The flow path for each ECCS pump must maintain its designed independence to ensure that no single failure can disable more than one ECCS pump.

BASES

LCO (continued)

As indicated in the LCO Note, the SI flow paths may be isolated for 2 hours in MODE 3, under controlled conditions, to perform pressure isolation valve testing per SR 3.4.14.1. The flow path is readily restorable from the control room or the valves are opened under administrative controls that ensure prompt closure when required. These administrative controls consist of stationing a dedicated operator at the valve controls, who is in continuous communication with the control room.

The two auxiliary component cooling water pumps are started during the injection phase to maintain component cooling water flow to the containment recirculation pump motor coolers; however, this cooling function is not required to protect the recirculation pump motors from the containment atmosphere. Therefore, the auxiliary component cooling water pumps are not required for containment recirculation pump OPERABILITY.

APPLICABILITY

In MODES 1, 2, and 3, the ECCS OPERABILITY requirements for the limiting Design Basis Accident, a large break LOCA, are based on full power operation. Although reduced power would not require the same level of performance, the accident analysis does not provide for reduced cooling requirements when at low reactor power or in MODE 3. The HHSI pump performance requirements are based on a small break LOCA. MODE 2 and MODE 3 requirements are bounded by the MODE 1 analysis.

This LCO is only applicable in MODE 3 and above. In MODE 4, the SI signal setpoint is manually bypassed by operator control, and system functional requirements are relaxed as described in LCO 3.5.3, "ECCS - Shutdown."

In MODES 5 and 6, plant conditions are such that the probability of an event requiring ECCS injection is extremely low. Core cooling requirements in MODE 5 are addressed by LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled," and LCO 3.4.8, "RCS Loops - MODE 5, Loops Not Filled." MODE 6 core cooling requirements are addressed by LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level," and LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level."

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.7

Periodic inspections of the containment and recirculation sumps ensure that they are unrestricted and stay in proper operating condition. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the need to have access to the location. This Frequency is sufficient to detect abnormal degradation based on industry operating experience.

REFERENCES

1. 10 CFR 50, Appendix A.
2. 10 CFR 50.46.
3. UFSAR, Section 6.2.
4. UFSAR, Chapter 14.
5. NRC Memorandum to V. Stello, Jr., from R.L. Baer, "Recommended Interim Revisions to LCOs for ECCS Components," December 1, 1975.
6. IE Information Notice No. 87-01.

BASES

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to inoperable ECCS High Head Safety Injection subsystems when entering MODE 4. There is an increased risk associated with entering MODE 4 from MODE 5 with an inoperable ECCS high head subsystems and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1

With no ECCS RHR subsystem OPERABLE, the plant is not prepared to respond to a loss of coolant accident or to continue a cooldown using the RHR pumps and heat exchangers. The Completion Time of immediately to initiate actions that would restore at least one ECCS RHR subsystem to OPERABLE status ensures that prompt action is taken to restore the required cooling capacity. Normally, in MODE 4, reactor decay heat is removed from the RCS by an RHR loop. If no RHR loop is OPERABLE for this function, reactor decay heat must be removed by some alternate method, such as use of the steam generators. The alternate means of heat removal must continue until the inoperable RHR loop components can be restored to operation so that decay heat removal is continuous.

With both RHR pumps and heat exchangers inoperable, it would be unwise to require the plant to go to MODE 5, where the only available heat removal system is the RHR. Therefore, the appropriate action is to initiate measures to restore one ECCS RHR subsystem and to continue the actions until the subsystem is restored to OPERABLE status.

B.1

With one of the two required ECCS HHSI subsystems inoperable, the remaining HHSI subsystem and the RHR subsystem maintain substantial capability for the mitigation of a large spectrum of both large and small break LOCAs in MODE 4. Therefore, a Completion Time of 48 hours for restoration of the inoperable subsystem is warranted.

BASES

ACTIONS (continued)

C.1

With no ECCS HHSI subsystem OPERABLE, due to the inoperability of the pump or flow path from the RWST, the plant is not prepared to provide high pressure response to Design Basis Events requiring SI. The 1 hour Completion Time to restore at least one ECCS HHSI subsystem to OPERABLE status ensures that prompt action is taken to provide the required cooling capacity or to initiate actions to place the plant in MODE 5, where an ECCS subsystem is not required.

D.1

When the Required Actions of Conditions B or C cannot be completed within the required Completion Time, a controlled shutdown should be initiated. Twenty-four hours is a reasonable time, based on operating experience, to reach MODE 5 in an orderly manner and without challenging plant systems or operators.

SURVEILLANCE REQUIREMENTS

SR 3.5.3.1

The applicable Surveillance descriptions from Bases 3.5.2 apply.

REFERENCES

The applicable references from Bases 3.5.2 apply.

BASES

BACKGROUND (continued)

b. Sufficient water volume exists in the recirculation or containment sump to support continued operation of the ECCS pumps at the time of transfer to the recirculation mode of cooling, and

c. The reactor remains subcritical following a LOCA.

Insufficient water in the RWST could result in insufficient cooling capacity when the transfer to the recirculation mode occurs. Improper boron concentrations could result in a reduction of SDM or excessive boric acid precipitation in the core following the LOCA, as well as excessive caustic stress corrosion of mechanical components and systems inside the containment due to improper pH in the sumps.

APPLICABLE SAFETY ANALYSES

During accident conditions, the RWST provides a source of borated water to the ECCS and Containment Spray System pumps. As such, it provides containment cooling and depressurization, core cooling, and replacement inventory and is a source of negative reactivity for reactor shutdown (Ref. 1). The design basis transients and applicable safety analyses concerning each of these systems are discussed in the Applicable Safety Analyses section of B 3.5.2, "ECCS - Operating," B 3.5.3, "ECCS - Shutdown," and B 3.6.6, "Containment Spray System and Containment Fan Cooler Unit (FCU) System." These analyses are used to assess changes to the RWST in order to evaluate their effects in relation to the acceptance limits in the analyses.

The RWST must also meet volume, boron concentration, and temperature requirements for non-LOCA events. The volume is not an explicit assumption in non-LOCA events since the required volume is a small fraction of the available volume. The deliverable volume limit is set by the LOCA and containment analyses. For the RWST, the deliverable volume is different from the total volume contained since, due to the design of the tank, more water can be contained than can be delivered. The minimum boron concentration is an explicit assumption in the main steam line break (MSLB) analysis to ensure the required shutdown capability. The maximum temperature ensures that the amount of cooling provided from the RWST is consistent with safety analysis assumptions; the minimum is an assumption in both the MSLB and inadvertent ECCS actuation analyses, although the inadvertent ECCS actuation event is typically nonlimiting.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The IP2 ESFAS design does not include automatic switchover from the safety injection mode to the recirculation mode of operation based on low level in the RWST coincident with a safety injection signal. This function is performed manually by the operator who must be alerted by redundant alarms that annunciate RWST level low low. The switchover to the cold leg recirculation phase is manually initiated when the RWST level has reached the low low alarm setpoint and sufficient coolant inventory to support pump operation in recirculation mode is verified to be in the containment.

The RWST level low low alarm setpoint has both upper and lower limits. The upper limit is set to ensure that switchover does not occur until there is adequate water inventory in the containment to provide ECCS pump suction. (This is confirmed by recirculation and/or containment sump level indication.) The lower limit is set to ensure switchover occurs before the RWST empties, to prevent ECCS pump damage.

Requiring 2 channels of RWST level low low alarm ensures that the alarm function will be available assuming a single failure of one channel.

The RWST satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The RWST ensures that an adequate supply of borated water is available to cool and depressurize the containment in the event of a Design Basis Accident (DBA), to cool and cover the core in the event of a LOCA, to maintain the reactor subcritical following a DBA, and to ensure adequate level in the recirculation and containment sump to support ECCS operation in the recirculation mode.

To be considered OPERABLE, the RWST must meet the water volume, boron concentration, and temperature limits established in the SRs.

RWST OPERABILITY requires OPERABILITY of two channels of the RWST level low low alarm. This is required because the IP2 ESFAS design does not include automatic switchover from the safety injection mode to the recirculation mode of operation based on low level in the RWST coincident with a safety injection signal. This function is performed manually by the operator who must be alerted by redundant alarms that annunciate RWST level low low. The switchover to the cold leg recirculation phase is manually initiated when the RWST level has reached the low low alarm setpoint and sufficient coolant inventory to support pump operation in recirculation mode is verified to be in the containment.

BASES

APPLICABILITY

In MODES 1, 2, 3, and 4, RWST OPERABILITY requirements are dictated by ECCS and Containment Spray System OPERABILITY requirements. Since both the ECCS and the Containment Spray System must be OPERABLE in MODES 1, 2, 3, and 4, the RWST must also be OPERABLE to support their operation. Core cooling requirements in MODE 5 are addressed by LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled," and LCO 3.4.8, "RCS Loops - MODE 5, Loops Not Filled." MODE 6 core cooling requirements are addressed by LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level," and LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level."

ACTIONS

A.1

With RWST boron concentration or borated water temperature not within limits of SR 3.5.4.3 or SR 3.5.4.1, respectively, they must be returned to within limits within 8 hours. Under these conditions neither the ECCS nor the Containment Spray System can perform its design function. Therefore, prompt action must be taken to restore the tank to OPERABLE condition. The 8 hour limit to restore the RWST temperature or boron concentration to within limits was developed considering the time required to change either the boron concentration or temperature and the fact that the contents of the tank are still available for injection.

B.1

Condition B applies when one channel of the RWST level low low alarm is inoperable. Required Action B.1 requires restoring the inoperable channel to OPERABLE status within 7 days. The 7 day Completion Time for restoration of redundancy to the alarm function is needed because the IP2 ESFAS design does not include automatic switchover from the safety injection mode to the recirculation mode of operation based on low level in the RWST coincident with a safety injection signal. This function is performed manually by the operator who is alerted by the RWST level low low alarm as the primary indicator for determining the time for the switchover. The 7 day Completion Time for restoration of redundancy for this alarm function is acceptable because of the remaining alarm channel and the availability of containment and recirculation sump level indication in the control room.

BASES

ACTIONS *(continued)*

C.1

With the RWST inoperable for reasons other than Condition A or B (e.g., water volume not within limit of SR 3.5.4.2 or both RWST level alarms inoperable), it must be restored to OPERABLE status within 1 hour.

In this Condition, neither the ECCS nor the Containment Spray System can perform its design function. Therefore, prompt action must be taken to restore the tank to OPERABLE status or to place the plant in a MODE in which the RWST is not required. The short time limit of 1 hour to restore the RWST to OPERABLE status is based on this condition simultaneously affecting redundant trains.

D.1 and D.2

If the RWST cannot be returned to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.5.4.1

The RWST borated water temperature should be verified every 24 hours to be within the limits assumed in the accident analyses band. This Frequency is sufficient to identify a temperature change that would approach either limit and has been shown to be acceptable through operating experience.

SR 3.5.4.2

The RWST water volume should be verified every 7 days to be above the required minimum level in order to ensure that a sufficient initial supply is available for injection and containment spray and to support continued ECCS operation on recirculation. Since the RWST volume is normally stable and is protected by an alarm, a 7 day Frequency is appropriate and has been shown to be acceptable through operating experience.

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. - NOTE - Only applicable to penetration flow paths with two or more containment isolation valves. One or more penetration flow paths with one containment isolation valve inoperable for reasons other than Condition D.	A.1	Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured.	4 hours
	AND		
	A.2	- NOTES - 1. Isolation devices in high radiation areas may be verified by use of administrative means. 2. Isolation devices that are locked, sealed, or otherwise secured may be verified by use of administrative means. Verify the affected penetration flow path is isolated.	Once per 31 days for isolation devices outside containment AND Prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days for isolation devices inside containment

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. - NOTE - Only applicable to penetration flow paths with two or more containment isolation valves. One or more penetration flow paths with two or more containment isolation valves inoperable for reasons other than Condition D.	B.1	Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	4 hours
C. - NOTE - Only applicable to penetration flow paths with only one containment isolation valve and a closed system. One or more penetration flow paths with one containment isolation valve inoperable.	C.1	Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	72 hours
	<u>AND</u>		
	C.2	- NOTES - 1. Isolation devices in high radiation areas may be verified by use of administrative means. 2. Isolation devices that are locked, sealed, or otherwise secured may be verified by use of administrative means. Verify the affected penetration flow path is isolated.	Once per 31 days

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3 Containment Isolation Valves

BASES

BACKGROUND

The containment isolation valves (CIVs) form part of the containment pressure boundary and provide a means for fluid penetrations not serving accident consequence limiting systems to be provided with two isolation barriers that are closed on a containment isolation signal. These isolation devices are either passive or active (automatic). Manual valves, de-activated automatic valves secured in their closed position (including check valves with flow through the valve secured), blind flanges, and closed systems are considered passive devices. Check valves, or other automatic valves designed to close without operator action following an accident, are considered active devices. Two barriers in series are provided for each penetration so that no single credible failure or malfunction of an active component can result in a loss of isolation or leakage that exceeds limits assumed in the safety analyses. One of these barriers may be a closed system. These barriers (typically containment isolation valves) make up the Containment Isolation System.

Automatic isolation signals are produced during accident conditions. Containment Phase "A" isolation occurs upon receipt of a safety injection signal. The Phase "A" isolation signal isolates nonessential process lines in order to minimize leakage of fission product radioactivity. Containment Phase "B" isolation occurs upon receipt of a containment pressure High-High signal and isolates the remaining process lines, except systems required for accident mitigation. In addition to the isolation signals listed above, the containment purge supply and exhaust isolation valves and the containment pressure relief line isolation valves receive an isolation signal on a containment high radiation condition or manual signal as required by LCO 3.3.6, "Containment Purge System and Pressure Relief Line Isolation Instrumentation." Additionally, a high radiation signal from the monitor in the plant vent will also isolate the containment purge system and pressure relief line. As a result, the containment isolation valves (and blind flanges) help ensure that the containment atmosphere will be isolated from the environment in the event of a release of fission product radioactivity to the containment atmosphere as a result of a Design Basis Accident (DBA).

The OPERABILITY requirements for containment isolation valves help ensure that containment is isolated within the time limits assumed in the safety analyses. Therefore, the OPERABILITY requirements provide assurance that the containment function assumed in the safety analyses will be maintained.

BASES

BACKGROUND (continued)

Containment Purge Supply and Exhaust Isolation Valves

The containment purge system is independent of the primary auxiliary building exhaust system, (except for the common exhaust fans) and includes provisions for both supply and exhaust air. The supply system includes roughing filters, heating coils, fan, supply penetration with two 36 inch butterfly valves for isolation, and a purge supply distribution header inside containment. The exhaust system includes exhaust penetration with two 36 inch butterfly valves, exhaust ductwork, filter bank with roughing, HEPA and charcoal filters, fans and exhaust vent. The design full purge flow rate is 25,000 cfm.

The containment purge system isolation valves are not normally opened when in MODES 1, 2, 3 and 4 because containment pressure control is provided by the containment pressure relief line. However, containment purge system isolation valves may be opened, as needed, for pressure control, ALARA or air quality considerations for personnel entry, or for Surveillances that require the valves to be open. This is acceptable because the containment purge supply duct and exhaust duct are each equipped with two solenoid-controlled, pneumatically operated butterfly valves (one inside and one outside of the containment) to be used for isolation purposes. The valves are automatically closed upon receipt of a safety injection signal or high-containment radiation signal and are spring-loaded to fail closed on loss of control signal or instrument air. Valve travel is limited to a maximum of 60 degrees to ensure that the valves will be able to close against the maximum calculated design-basis accident pressure of 47 psig. An adjustable position setting on the actuators allows the valves to be opened to a full 90 degree position when containment integrity is not required.

When the containment purge system isolation valves are closed, the space between each set of valves is pressurized above containment design pressure from the WC&PPS in accordance with LCO 3.6.10, "Weld Channel and Penetration Pressurization System (WC&PPS)."

Containment Pressure Relief Line Isolation Valves

The normal pressure changes in the containment during reactor power operation, and during plant cooldown are handled by the containment pressure relief line. Because the line is intended to be opened periodically during reactor power operation, three 10 inch butterfly valves in series are provided for isolation, one inside and two outside the containment. The design and operation of these valves is similar to the containment purge

BASES

BACKGROUND (continued)

supply and exhaust isolation valves. The valves are automatically closed upon receipt of a safety injection signal or high-containment radiation signal and are equipped with an accumulator to assure each valve can close even if the air supply is lost. Valve travel is limited to a maximum of 60 degrees to ensure that the valves will be able to close against the maximum calculated design-basis accident pressure of 47 psig.

When the containment pressure relief line isolation valves are closed, the two spaces between the three valves is pressurized above containment design pressure from the WC&PPS in accordance with LCO 3.6.10, "Weld Channel and Penetration Pressurization System (WC&PPS)."

APPLICABLE SAFETY ANALYSES

The containment isolation valve LCO was derived from the assumptions related to establishing the containment boundary during major accidents. As part of the containment boundary, containment isolation valve OPERABILITY supports leak tightness of the containment. Therefore, the safety analysis of any event requiring isolation of containment is applicable to this LCO.

The DBAs that result in a release of radioactive material within containment are a loss of coolant accident (LOCA) and a rod ejection accident (Ref. 1). In the analyses for each of these accidents, it is assumed that containment isolation valves are either closed or function to close within the required isolation time following event initiation. This ensures that potential paths to the environment through containment isolation valves (including containment purge valves) are minimized. The containment purge (supply and exhaust) and the containment pressure relief line may be opened in MODES 1, 2, 3 and 4, as needed, for pressure control, ALARA or air quality considerations for personnel entry, or for Surveillances that require the valves to be open. This is acceptable because the containment purge (supply and exhaust) and the containment pressure relief line are each equipped with redundant containment isolation valves that are automatically closed upon receipt of a safety injection signal or high-containment radiation signal in containment.

The DBA analysis assumes that, within 60 seconds after the accident, isolation of the containment is complete and leakage terminated except for the design leakage rate, L_a. The containment isolation total response time of 60 seconds includes signal delay, diesel generator startup (for loss of offsite power), and containment isolation valve stroke times.

BASES

ACTIONS (continued)

isolation boundary and the relative importance of maintaining containment integrity during MODES 1, 2, 3, and 4. In the event the affected penetration flow path is isolated in accordance with Required Action C.1, the affected penetration flow path must be verified to be isolated on a periodic basis. This periodic verification is necessary to assure leak tightness of containment and that containment penetrations requiring isolation following an accident are isolated. The Completion Time of once per 31 days for verifying that each affected penetration flow path is isolated is appropriate because the valves are operated under administrative controls and the probability of their misalignment is low.

Condition C is modified by a Note indicating that this Condition is only applicable to those penetration flow paths with only one containment isolation valve and a closed system. The closed system must meet the requirements of Ref. 3. This Note is necessary since this Condition is written to specifically address those penetration flow paths in a closed system.

Required Action C.2 is modified by two Notes. Note 1 applies to valves and blind flanges located in high radiation areas and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned. Therefore, the probability of misalignment of these valves, once they have been verified to be in the proper position, is small.

D.1

With the hydrostatically tested valve leakage not within limit of SR 3.6.3.8, the potential exists for flooding the Containment Recirculation Pumps during long term post-accident cooling. The leakage must be restored to within limits. Restoration can be accomplished by isolating the penetration(s) that caused the limit to be exceeded by use of one closed and de-activated automatic valve, closed manual valve, or blind flange. When a penetration is isolated the leakage rate for the isolated penetration is assumed to be the actual pathway leakage through the isolation device. If two isolation devices are used to isolate the penetration, the leakage rate is assumed to be the

BASES

SURVEILLANCE REQUIREMENTS (continued)

Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 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 that these components usually pass this Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.3.7

Verifying that each containment purge supply and exhaust isolation valves (FCV-1170, FCV-1171, FCV-1172, and FCV-1173) and the containment pressure relief line isolation valves (PCV-1190, PCV-1191 and PCV-1192) is blocked to restrict opening to ≤ 60 degrees is required to ensure that the valves can close under DBA conditions within the times assumed in the analyses of References 1 and 2. If a LOCA occurs, the purge valves must close to maintain containment leakage within the values assumed in the accident analysis. At other times when purge valves are required to be capable of closing (e.g., during movement of recently irradiated fuel assemblies), pressurization concerns are not present, thus the purge valves can be fully open. The 24 month Frequency is appropriate because the blocking devices are typically removed only during a refueling outage.

SR 3.6.3.8

Technical Specification 5.5.14, Containment Leakage Rate Testing Program, includes a limit for the inleakage into containment from the containment isolation valves sealed with service water. The maximum permissible inleakage rate of 0.36 gpm per fan-cooler from the containment isolation valves sealed with service water is intended to prevent flooding the internal recirculation pumps during the full 12-month post-accident recirculation period. The results for this inleakage test are not counted against the acceptance criteria for the Type B and C tests that are also performed as part of the SR. The Frequency for this SR is specified in Technical Specification 5.5.14 and is based on operating experience and the plant conditions necessary to perform this test.

REFERENCES

1. UFSAR, Section 14.
2. UFSAR, Section 5.

BASES

REFERENCES (continued)

3. Standard Review Plan 6.2.4.

4. Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Amendment No. 211 to Facility Operating License No. DPR-26, July 27, 2000.

5. Generic Issue B-24.

L.5 3.6.3: Containment Isolation Valves

Rev. 0 Category Less Restrictive (Cat V): Relaxation of LCO Requirement

DOC Summary:

Expands conditions that allow opening the containment purge supply and exhaust isolation valves and the pressure relief line isolation valves from "containment pressure control, or to facilitate safety-related surveillance or safety-related maintenance" to "pressure control, ALARA or air quality considerations for personnel entry, or for Surveillances that require the valves to be open."

Description of Change

CTS 3.6.A.2 specifies that the containment purge supply and exhaust isolation valves and the pressure relief line isolation valves "may only be open for safety related reasons." CTS 3.6.A.2 (Note 1) clarifies that safety related reasons include "include containment pressure control, or to facilitate safety-related surveillance or safety-related maintenance."
ITS SR 3.6.3.1 and ITS SR 3.6.3.2 maintain the restrictions for opening the containment purge supply and exhaust isolation valves and the pressure relief line isolation valves; however, ITS 3.6.3 allows thes valves to be open for pressure control, ALARA or air quality considerations for personnel entry, or for Surveillances that require the valves to be open.

Justification for Change:

This change is needed and is acceptable because ITS SR 3.6.3.1 and ITS SR 3.6.3.2 allow the valves t be open only as needed to satisfy their design function. Additionally, the containment purge supply duct and exhaust ducts and the containment pressure relief line are each equipped with redundant automatic containment isolation valves. The valves are automatically closed upon receipt of ESFAS signal or high containment radiation signal and are spring-loaded to fail closed on loss of control signal or instrument air. Valve travel is limited to a maximum of 60 degrees to ensure that the valves will be able to close against the maximum calculated design-basis accident pressure of 47 psig. Additionally, there is a low probability of an event during the limited period of time that the valves are open.

L.6 3.6.3: Containment Isolation Valves

Rev. 1 Category Less Restrictive (Unique):

DOC Summary:

Superceded by Amendment 223.

Description of Change

Superceded by Amendment 223.

Justification for Change:

Superceded by Amendment 223.

BASES

LCO

The initial containment average air temperature must be maintained less than or equal to the upper LCO temperature limit to ensure the resultant peak accident temperature is maintained below the containment design temperature during a DBA. As a result, the ability of containment to perform its design function is ensured.

The LCO limits for containment temperature are analytical limits. Therefore, an appropriate allowance for instrument uncertainty must be applied when ensuring these limits are met.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining containment average air temperature within the limits is not required in MODE 5 or 6.

ACTIONS

A.1

When containment average air temperature is not within the limits of the LCO, it must be restored to within limits within 8 hours. This Required Action is necessary to return operation to within the bounds of the containment analysis. The 8 hour Completion Time is acceptable considering the sensitivity of the analysis to variations in this parameter and provides sufficient time to correct minor problems.

B.1 and B.2

If the containment average air temperature cannot be restored to within its limits within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES

BACKGROUND (continued)

iodine removal during the containment recirculation phase. In this configuration, the RHR heat exchangers provide the necessary cooling of the recirculated containment spray.

The Containment Spray System provides a spray of cold borated water into the upper regions of containment to reduce the containment pressure and temperature and to reduce fission products from the containment atmosphere during a DBA. The RWST solution temperature is an important factor in determining the heat removal capability of the Containment Spray System during the injection phase. In the recirculation mode of operation, heat is removed from the recirculation sump or the containment sump water by the residual heat removal coolers. Both trains of the Containment Spray System provides adequate spray to meet the system design requirements for containment heat removal even if the Fan Cooler System is not OPERABLE.

The recirculation system pH control system will add trisodium phosphate to the sump when the level of the boric acid solution from the containment spray and the coolant lost from the reactor coolant system rises above the level of the trisodium phosphate baskets in containment. The resulting alkaline pH of the spray enhances the ability of the re-circulated spray to scavenge fission products from the containment atmosphere. The trisodium phosphate also ensures an alkaline pH for the solution recirculated in the containment sump. The alkaline pH of the recirculation sump or the sump water minimizes the evolution of iodine and minimizes the occurrence of chloride and caustic stress corrosion on mechanical systems and components exposed to the fluid.

The Containment Spray System is actuated either automatically by a containment High-High pressure signal or manually. An automatic actuation starts the two containment spray pumps, opens the containment spray pump discharge valves, and begins the injection phase. A manual actuation of the Containment Spray System requires the operator to actuate two separate push buttons on the main control board to begin the same sequence. The injection phase continues until the RWST water supply is exhausted. After the Refueling Water Storage Tank has been exhausted, the containment recirculation pumps or the Residual Heat Removal (RHR) pumps may be used to supply the Containment Spray ring headers for the long-term containment cooling and iodine removal during the containment recirculation phase. In this configuration, the RHR heat exchangers provide the necessary cooling of the recirculated containment spray. The Containment Spray System in the recirculation mode may be used to maintain an equilibrium temperature between the containment atmosphere and the

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.6.9

This SR verifies that minimum air flow through each FCU equals the air flow assumed in the accident analysis for heat removal from the containment. The 24 month Frequency is based on engineering judgment.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 38, GDC 39, GDC 40, GDC 41, GDC 42, and GDC 43.
2. 10 CFR 50, Appendix K.
3. UFSAR, Section 6.3.
4. UFSAR, Section 6.4.
5. UFSAR, Section 14.3.
6. ASME, Boiler and Pressure Vessel Code, Section XI.
7. Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Amendment No. 211 to Facility Operating License No. DPR-26, July 27, 2000.

3.6 CONTAINMENT SYSTEMS

3.6.7 Recirculation pH Control System

LCO 3.6.7 The Recirculation pH Control System shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Recirculation pH Control System inoperable.	A.1	Restore Recirculation pH Control System to OPERABLE status.	72 hours
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 3.	6 hours
	AND		
	B.2	Be in MODE 5.	84 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.7.1	Perform a visual inspection of the four trisodium phosphate storage baskets to verify each of the following: a. Each storage basket is in place and intact; and, b. Collectively contain ≥ 8000 pounds (148 cubic feet) of trisodium phosphate (w/12 hydrates), or equivalent.	24 months

B 3.6 CONTAINMENT SYSTEMS

B 3.6.7 Recirculation pH Control System

BASES

BACKGROUND

The recirculation pH control system is a passive safeguard with baskets of trisodium phosphate located in the containment sump area. Trisodium phosphate is stored in four baskets at the 46 foot elevation inside the containment building (Ref. 1).

During the injection phase the level of the boric acid solution from the containment spray and the coolant lost from the reactor coolant system will rise above the trisodium phosphate baskets. The trisodium phosphate will dissolve into the solution, providing a solution with pH in the range of 7 to 9.5 to enhance long-term iodine retention in the solution and to minimize corrosion (Ref. 1).

Section 6.5.2 of the Standard Review Plan (Ref. 3) specifies a pH value greater than or equal to 7.0 to assure continued retention of iodine in the sump solution. WCAP-14542, "Evaluation of the Radiological Consequences from a Loss of Coolant Accident at IP2 Using NUREG-1465 Source Term Methodology," dated July 1996 (Ref. 4), states that, for IP2, the mass of trisodium phosphate (TSP) required to provide an equilibrium sump solution pH of 7.0 is less than 4,000 pounds. To address the potential for long term generation of acids in the containment, this amount is doubled to 8,000 pounds. The initial containment spray will be boric acid solution from the refueling water storage tank which has a pH of approximately 4.5. As the initial spray solution and, subsequently, the recirculation solution comes in contact with the TSP, the TSP dissolves raising the pH of the sump solution to an equilibrium value between 7.0 and 9.5 (Ref. 5).

APPLICABLE SAFETY ANALYSES

The recirculation pH control system is a passive safeguard with the baskets of trisodium phosphate located in the containment sump area. The OPERABILITY of the recirculation pH control system ensures that there is sufficient trisodium phosphate (TSP) available in containment to guarantee a sump pH >7.0 during the recirculation phase of a postulated LOCA. The mass of trisodium phosphate (TSP) required to provide an equilibrium sump solution pH of 7.0 is less than 4,000 pounds. To address the potential for long term generation of acids in the containment, this amount is doubled to 8,000 pounds. The initial containment spray will be boric acid solution from the refueling water storage tank which has a pH of approximately 4.5. As the initial spray solution and, subsequently, the recirculation solution comes in contact with the TSP, the TSP dissolves raising the pH of the sump solution to an equilibrium value between 7.0 and 9.5 (Ref. 5).

BASES

APPLICABLE SAFETY ANALYSES (continued)

The Recirculation pH Control System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The recirculation pH control system is necessary to reduce the release of radioactive material to the environment in the event of a DBA. To be considered OPERABLE, each of the four storage trisodium baskets must be in place and intact and collectively contain ≥ 8000 pounds (148 cubic feet) of trisodium phosphate (w/12 hydrates), or equivalent.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment requiring the operation of the recirculation pH control system. The recirculation pH control system assists in reducing the iodine fission product inventory prior to release to the environment.

In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Thus, the recirculation pH control system is not required to be OPERABLE in MODE 5 or 6.

ACTIONS

A.1

If the recirculation pH control system is inoperable, it must be restored to OPERABLE within 72 hours. The pH adjustment of the recirculation pH control system flow for corrosion protection and iodine removal enhancement is reduced in this condition. The Containment Spray system would still be available and would remove some iodine from the containment atmosphere in the event of a DBA (Ref. 6). The 72 hour Completion Time takes into account the low probability of the worst case DBA occurring during this period.

B.1 and B.2

If the recirculation pH control system cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 84 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems. The extended interval to reach MODE 5 allows 48 hours for restoration of recirculation pH control system in

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.10.1

This SR requires periodic verification during plant operation that the required portions of each WC&PPS zone are maintained at a pressure greater than the containment peak accident pressure. This SR is satisfied by verification of zone pressure on each of the four WC&PPS zones is above the specified limit. The 31 day Frequency is acceptable because there are low pressure alarms in the Control Room to ensure that operators are aware that all WC&PPS zones are pressurized.

SR 3.6.10.2

This SR requires periodic verification during plant operation that the WC&PPS air consumption is ≤ 0.2% of the containment free volume per day. This SR is performed by taking the sum of the reading on the flow sensing devices located in each of the zone headers. A WC&PPS total flow rate of 15.2 scfm, if sustained for 24 hours, is equivalent to 0.2% of the containment free volume at a pressure of 47 psig. The 31 day Frequency recognizes that WC&PPS air consumption indication and high flow alarms are provided in the control room.

SR 3.6.10.3

This SR, sometimes called the sensitive leak rate test, ensures that the leakage rate for the WC&PPS is ≤ 0.2% of the containment free volume per day when pressurized to ≥ 52 psig above containment pressure. The sensitive leak rate test includes only the volume of the weld channels, double penetrations, and containment isolation valves supported by WC&PPS. This test is considered more sensitive than the integrated leakage rate test, as the instrumentation used permits a direct measurement of leakage from the pressurized zones. The 24 month Frequency is acceptable because experience has shown that the WC&PPS usually passes this Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. UFSAR, Section 6.6.
2. 10 CFR 50.67.
3. Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Amendment No. 211 to Facility Operating License No. DPR-26, July 27, 2000.

BASES

ACTIONS (continued)

The maximum THERMAL POWER corresponding to the heat removal capacity of the remaining OPERABLE MSSVs is determined via a conservative heat balance calculation as described in the attachment to Reference 6, with an appropriate allowance for Nuclear Instrumentation System trip channel uncertainties.

Required Action B.2 is modified by a Note, indicating that the Power Range Neutron Flux-High reactor trip setpoint reduction is only required in MODE 1. In MODES 2 and 3 the reactor protection system trips specified in LCO 3.3.1, "Reactor Protection System Instrumentation," already establish a trip setpoint lower than that required by this LCO.

The allowed Completion Times are reasonable based on operating experience to accomplish the Required Actions in an orderly manner without challenging unit systems.

C.1 and C.2

If the Required Actions are not completed within the associated Completion Time, or if one or more steam generators have ≥ 4 inoperable MSSVs, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 12 hours. The allowed Completion Times are 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 3.7.1.1

This SR verifies the OPERABILITY of the MSSVs by the verification of each MSSV lift setpoint in accordance with the Inservice Testing Program. The ASME Code, Section XI (Ref. 4), requires that safety and relief valve tests be performed in accordance with ANSI/ASME OM-1-1987 (Ref. 5). According to Reference 5, the following tests are required:

a. Visual examination,

b. Seat tightness determination,

c. Setpoint pressure determination (lift setting), and

d. Compliance with owner's seat tightness criteria.

BASES

ACTIONS (continued)

function to mitigate the failure of an MSIV associated with any of the other SGs. Additionally, an inoperable MSCV does not affect the consequences of an SLB downstream of the MSIV.

The 72 hour Completion Time is acceptable because of the following: all MSIVs are Operable, there is a low probability of the failure of an MSIV during the 72 hour period that one or more MSCVs are inoperable; and, there is a low probability of an accident that would require a closure of the MSCVs or MSIVs during this period.

B.1 and B.2

If the MSCV cannot be restored to OPERABLE status within 72 hours, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in MODE 2 within 6 hours and all MSIVs must be closed within 14 hours. The Completion Times are reasonable, based on operating experience, to reach MODE 2 and to close the MSIVs in an orderly manner and without challenging unit systems.

C.1

With one MSIV inoperable in MODE 1, action must be taken to restore OPERABLE status within 72 hours. Some repairs to the MSIV can be made with the unit hot. The 72 hour Completion Time for restoration of an inoperable MSIV is acceptable because the plant remains within the SGTR and SLB accident analysis assumptions (including assumptions regarding single failure of an MSIV) except for an SLB that occurs downstream of the MSIVs. For an SLB that occurs downstream of the MSIVs, IP2 remains within the accident analysis assumptions except for the ability to tolerate the random failure of a second MSIV during the 72 hour allowable out of service time for the one MSIV permitted to be inoperable.

D.1

If the MSIV cannot be restored to OPERABLE status within 72 hours, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in MODE 2 within 6 hours and Condition E would be entered. The Completion Times are reasonable, based on operating experience, to reach MODE 2 and to close the MSIVs in an orderly manner and without challenging unit systems.

BASES

ACTIONS (continued)

E.1 and E.2

Condition E is modified by a Note indicating that separate Condition entry is allowed for each MSIV.

Since the MSIVs are required to be OPERABLE in MODES 2 and 3, the inoperable MSIVs may either be restored to OPERABLE status or closed. When closed, the MSIVs are already in the position required by the assumptions in the safety analysis.

The 8 hour Completion Time is reasonable, based on operating experience, to close the MSIVs after reaching MODE 2.

For inoperable MSIVs that cannot be restored to OPERABLE status within the specified Completion Time, but are closed, the inoperable MSIVs must be verified on a periodic basis to be closed. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of MSIV status indications available in the control room, and other administrative controls, to ensure that these valves are in the closed position.

F.1 and F.2

If one MSIV is inoperable when one or more MSCVs are inoperable, then more than one SG may blowdown following an SLB upstream of an MSIV and the plant is outside of the analysis assumptions. The plant remains within the analysis assumptions for an SLB downstream of an MSIV although the ability to tolerate the failure if a second MSIV is lost. In this condition, all MSCVs must be restored to OPERABLE status or all MSIVs must be restored to OPERABLE status within 1 hour. The 1 hour Completion Time is acceptable because of the low probability of an accident that would require a closure of the MSCVs or MSIVs during this time period.

G.1 and G.2

If the MSIVs or MSCVs cannot be restored to OPERABLE status or are not closed within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed at least in MODE 3 within 6 hours, and in MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from MODE 2 conditions in an orderly manner and without challenging unit systems.

B 3.7 PLANT SYSTEMS

B 3.7.3 Main Feedwater Isolation

BASES

BACKGROUND

Isolation of the main feedwater system is necessary to mitigate various accident and transient conditions (main steamline breaks, steam generator tube ruptures, and excessive heat removal due to feedwater system malfunction). Main feedwater must be automatically isolated to prevent excessive Reactor Coolant System (RCS) cooldown, containment overpressure, and steam generator overfill. Main feedwater isolation is initiated by either an ESFAS safety injection (SI) signal or high steam generator water level. Main feedwater isolation to all four steam generators is provided by either of the following:

a. Closure of all four Main Feedwater Regulating Valves (MFRVs) and closure of all four Low Flow Main Feedwater Bypass Valves (FBVs); or,

b. Closure of both Main Boiler Feedwater Pump (MBFP) discharge valves which initiates closure of all eight Main Feedwater Isolation Valves (MFIVs), and the trip of both Main Boiler Feedwater Pumps (MBFPs).

Either of these combinations is capable of achieving main feedwater isolation to all four steam generators within the time limits assumed in the accident analysis. Note that closure of the eight MFIVs is not required to meet accident analysis assumptions.

Main feedwater isolation is initiated by a safety injection ESFAS signal or a high steam generator water level ESFAS signal either of which provides a direct signal that closes all four MFRVs within 8 seconds and all four Lo Flow FBVs within 15 seconds. If all eight of these valves close, main feedwater isolation to all four SGs is completed within time limits that satisfy accident analysis assumptions (Ref. 2).

To establish required redundancy for the main feedwater isolation safety function, the safety injection ESFAS signal or high steam generator water level ESFAS signal also provides a direct signal that closes the two MBFP discharge valves within 60 seconds. Although closure of the MBFP discharge valves provides complete isolation of main feedwater to all four SGs, closure of the MBFP discharge valves does not satisfy accident analysis assumptions. Therefore, when the MBFP discharge valves close in response to an ESFAS signal, the main boiler feed pump will automatically trip when the associated MBFP discharge valve moves off the open seat.

BASES

BACKGROUND (continued)

MBFP discharge valves closure and the MBFP trip are sufficient to satisfy accident analysis assumptions for peak containment pressure. However, this barrier does not isolate the SGs and containment from the significant amount of feedwater mass and energy in the three high pressure feedwater heaters and the feedwater piping located between the MBFP discharge valves and the SGs. Therefore, when both MBFP discharge valves move off the open seat, a signal is generated that initiates closure of the eight Main Feedwater Isolation Valves (MFIVs). The eight MFIVs are motor operated valves that are located near to and isolate the four MFRVs and the four Lo Flow FBVs. The MBFP trip occurs within 5 seconds and closure of the MFIVs occurs within 120 seconds of the ESFAS signal that initiated closure of the MBFP discharge valve. Although not required to satisfy accident analysis assumptions, closure of the eight MFIVs conservatively limits peak containment pressure following an SLB or excess feedwater event. The eight MFIVs are the following: four motor operated MFRV isolation valves (BFD-5, BFD-5-1, BFD-5-2 and BFD-5-3), and four motor operated Lo Flow FBVs isolation valves (BFD-90, BFD-90-1, BFD-90-2 and BFD-90-3).

In addition to the MFRVs, Lo Flow FBVs and the MSIVs, the main feedwater line and auxiliary feedwater line to each SG includes a check valve that is located outside containment. These check valves provide a pressure boundary that allows either the main feedwater system or auxiliary feedwater system to supply an SG and prevent blowdown of a SG if main and auxiliary feedwater pressure is lost.

The main feedwater isolation safety function and components are described in References 1 and 2.

APPLICABLE SAFETY ANALYSES

The design basis of the main feedwater isolation function is established by the analyses for the large SLB. Main feedwater isolation may also be relied on to terminate an SLB for core response analysis and excess feedwater event upon the receipt of a steam generator water level - high high signal or a feedwater isolation signal on high steam generator level.

Failure of main feedwater isolation following an SLB can result in additional mass and energy being delivered to the steam generators, contributing to cooldown. This failure also results in additional mass and energy releases following an SLB.

Main feedwater isolation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

ACTIONS (continued)

F.1 and F.2

If the main feedwater isolation safety function and/or required redundancy cannot be restored to OPERABLE status, or affected valves closed, or affected flow paths isolated within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 12 hours. The allowed Completion Times are 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 3.7.3.1 and SR 3.7.3.2

These SRs verify that each of the valves in both of the main feedwater isolation barriers close within the time limits assumed in the accident analysis. SR 3.7.3.1 requires verification that MFRVs and Lo Flow FBVs close within the following limits:

MFRVs (FCV-417, FCV-427, FCV-437, and FCV-447) close in ≤ 8 seconds; and

Lo Flow FBVs (FCV-417L, FCV-427L, FCV-437L, and FCV-447L) close in ≤ 15 seconds.

SR 3.7.3.2 requires verification that MBFP discharge valves and MBFP trips within the following limits:

MBFP discharge valves (BFD-2-21 and BFD-2-22) close in ≤ 60 seconds; and

MBFPs (BFP 21 and BFP 22) trip in ≤ 5 seconds.

These Surveillances are normally performed upon returning the unit to operation following a refueling outage. These valves should not be tested at power since even a part stroke exercise increases the risk of a valve closure with the unit generating power. This is consistent with the ASME Code, Section XI (Ref. 3), quarterly stroke requirements during operation in MODES 1 and 2.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The Frequency for these SRs is in accordance with the Inservice Testing Program.

SR 3.7.3.3

This SR verifies that each MFRV, Lo Flow FBV, and MBFP discharge valve will close and that each MBFP will trip on an actual or simulated actuation signal. This Surveillance is normally performed upon returning the plant to operation following a refueling outage.

The Frequency for this SR is every 24 months. The 24 month Frequency for testing is based on the refueling cycle. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, this Frequency is acceptable from a reliability standpoint.

REFERENCES

1. UFSAR, Section 10.2.
2. UFSAR, Section 14.2.
3. ASME, Boiler and Pressure Vessel Code, Section XI.

BASES

APPLICABLE SAFETY ANALYSES (continued)

to cool down the unit, the ADVs and main steam safety valves (MSSVs) are assumed to operate automatically to relieve steam and maintain the steam generator pressure below the design value. For the recovery from a steam generator tube rupture (SGTR) event, the operator is also required to perform a limited cooldown to establish adequate subcooling as a necessary step to terminate the primary to secondary break flow into the ruptured steam generator. The time required to terminate the primary to secondary break flow for an SGTR is more critical than the time required to cool down to RHR conditions for this event and also for other accidents. Thus, the SGTR is the limiting event for the ADVs.

The IP2 analysis of the radiological consequences of a SGTR (References 2 and 3) conservatively assumes no operator actions that would help to terminate the primary to secondary leakage such as controlled depressurization of the RCS to the ruptured steam generator pressure or subsequent termination of safety injection flow to stop primary to secondary leakage. If the operators take no action to respond to the event, the break flow will tend to an equilibrium RCS pressure where incoming safety injection flow is balanced by outgoing break flow. In the accident analysis, this equilibrium break flow is assumed to persist from plant trip until 30 minutes after the accident initiation. The analysis does not require that the operators demonstrate the ability to terminate break flow within 30 minutes from the start of the event. It is recognized that the operators may not be able to terminate break flow within 30 minutes for all postulated SGTR events. The purpose of the calculation is to provide conservatively high mass-transfer rates for use in the radiological consequences analysis. This is achieved by assuming a constant break flow at the equilibrium flow rate for a relatively long time period (i.e., 30 minutes). Because this analysis assumed a loss of offsite power, plant cool down occurs using the ADVs and the steam generator safety valves with the lowest lift setting.

Using the conservative assumptions described above, the radiological consequences analysis were determined assuming both a pre-accident iodine spike (RCS at 60 times the assumed maximum coolant equilibrium concentration limit of 1.0 mCi/gm of DOSE EQUIVALENT I-131) and an accident initiated iodine spike (RCS at the assumed maximum coolant equilibrium concentration limit of 1.0 mCi/gm of DOSE EQUIVALENT I-131).

For the pre-accident iodine spike scenario, the exclusion area boundary (EAB) dose is 4.4 rem total effective dose equivalent (TEDE) and the low population zone (LPZ) dose is 2.1 rem TEDE (Ref. 2). These results are well within the 10 CFR 50.67 limits of 25 rem TEDE (Ref. 4).

B 3.7 PLANT SYSTEMS

B 3.7.8 Service Water System (SWS)

BASES

BACKGROUND

The SWS provides a heat sink for the removal of process and operating heat from safety related components during a Design Basis Accident (DBA) or transient. During normal operation, and a normal shutdown, the SWS also provides this function for various safety related and nonsafety related components. The safety related function is covered by this LCO.

The SWS consists of two separate, 100% capacity, safety related, cooling water headers. Each header is supplied by three pumps and includes the pump strainers and the piping up to and including the isolation valves on individual components cooled by the SWS.

SWS heat loads are designated as either essential or non-essential. The essential SWS heat loads are those which must be supplied with cooling water immediately in the event of a LOCA and/or loss of offsite power (LOOP). Examples of essential loads are the diesel generators (DGs) and containment fan cooler units (FCUs). The non-essential SWS heat loads are those which are required following a postulated LOCA only after the switch over to the recirculation phase. The most significant non-essential loads are the component cooling water (CCW) heat exchangers.

The FCUs are connected in parallel to the essential SWS header. Normal SW flow to the FCUs is controlled by TCV-1103. Required ESFAS flow to all five FCUs is initiated when either (or both) of the redundant FCU ESFAS Service Water valves (TCV-1104 and TCV-1105) opens automatically in response to an ESFAS actuation signal.

The DGs are connected in parallel to the essential SWS header. Normal required ESFAS flow to all three DGs is initiated when either (or both) of the redundant DG ESFAS Service Water valves (FCV-1176 and FCV-1176A) opens automatically in response to an ESFAS actuation which starts the DGs.

Either of the two SWS headers can be aligned to supply the essential heat loads or the non-essential SWS heat loads. Both the essential and non-essential SWS headers are operated to support normal plant operation and the plant response to accidents and transients. The SWS pumps associated with the SWS header designated as the essential header will start automatically. The SWS pumps associated with the SWS header designated as the non-essential header must be manually started when

BASES

APPLICABILITY

In MODES 1, 2, 3, and 4, the SWS is a normally operating system that is required to support the OPERABILITY of the equipment serviced by the SWS and required to be OPERABLE in these MODES.

In MODES 5 and 6, the OPERABILITY requirements of the SWS are determined by the systems it supports.

ACTIONS

The Actions are modified by a Note that specifies that LCO 3.0.3 is not applicable for 8 hours while swapping the essential SWS header with the non-essential SWS header but only if LCO 3.7.8 will be met after the essential and non-essential header are swapped. This means that the essential and non-essential SWS headers may be cross-connected for up to 8 hours during transfer of the designated essential SWS header to the alternate SWS header. This is acceptable because the transfer is performed infrequently (approximately every 90 days) and the low probability of an event while the headers are cross connected.

A.1 and B.1

If one of the three required SWS pumps on the essential SWS header is inoperable (Condition A), three OPERABLE pumps must be restored to the essential SWS header within 72 hours. Likewise, if one of the two required SWS pumps on non-essential SWS header is inoperable (Condition B), the header must be restored so that there are two OPERABLE pumps for the non-essential SWS header within 72 hours. With one required SWS pump inoperable on either or both SWS headers, the remaining OPERABLE SWS pumps are adequate to perform the heat removal function. However, the overall reliability is reduced because a single failure in an OPERABLE SWS pump could result in loss of SWS function. The 72 hour Completion Time is based on the redundant capabilities afforded by the OPERABLE SWS pumps in the same header and the low probability of a DBA occurring during this time period.

C.1 and D.1

Required ESFAS flow to all three DGs is initiated when either of the redundant SW to DG ESFAS valves (FCV-1176 or FCV-1176A) opens automatically in response to an ESFAS actuation which starts the DGs. Similarly, required ESFAS flow to all five FCUs is initiated when either of the redundant SW to FCU ESFAS valves (TCV-1104 or TCV-1105) opens automatically in response to an ESFAS actuation signal. The SW to FCU ESFAS valves and SW to DG ESFAS valves are OPERABLE when they

B 3.7 PLANT SYSTEMS

B 3.7.10 Control Room Ventilation System (CRVS)

BASES

BACKGROUND

The CRVS provides a protected environment from which operators can control the unit following an uncontrolled release of radioactivity.

The Control Room Ventilation System consists of the following:

- A direct expansion air conditioning unit complete with a fan (CCRF-21) and steam heating coil. The design capacity of the unit is 9200 cfm. A backup fan (CCRCF-22) of the same design capacity is installed in parallel with the air conditioning unit;
- A single 2000 cfm filter unit consisting of two high efficiency particulate air (HEPA) filters;
- Two activated charcoal adsorbers for removal of gaseous activity (principally iodines);
- Two 100% capacity (2000 cfm ±10%) filter booster fans (CCRBF-21 and CCRBF-22);
- One locker room and toilet exhaust fan (K-8); and
- A single duct system that uses redundant dampers, controls and associated accessories to provide for three different air flow configurations.

The three CRVS air flow configurations are normal mode, incident 100% recirculation mode, and outside filtered air pressurization mode.

Normal mode (mode 1) for the CRVS is used to provide cooling or heating for the control room atmosphere. In this mode, control room air is recirculated through the air conditioning unit at a rate of approximately 8280 cfm. Outside makeup air is provided to makeup for the approximately 920 cfm that is exhausted through the toilet exhaust fan. In the CRVS normal mode, the HEPA/adsorber filter unit is bypassed.

Pressurization mode (mode 2) for the CRVS is used for protection against airborne radiation. In this mode, the control room is pressurized with outside air that is drawn through the HEPA/adsorber filter unit. Pressurization with filtered air minimizes inleakage of unfiltered air into the control room. This mode is established as follows:

BASES

BACKGROUND (continued)

- A safety injection signal or a high radiation signal from the control room monitor (RE-38-1 or RE-38-2) as required by LCO 3.3.7, "Control Room Ventilation System (CRVS) Actuation Instrumentation" will automatically place the CRVS in the pressurization mode (mode 2). In the pressurization mode, either of the two filter booster fans (CCRBF-21 or CCRBF-22) will maintain the control room at a slight positive pressure relative to adjacent areas.

- Toilet area exhaust fan (K-8) is tripped and the associated exhaust flow path is isolated by series redundant dampers (CCRD4 and CCRD5). This action completes the control room envelope to permit pressurization.

- Dampers (CCRA1 and CCRA2) in the flowpath that allows outside air to bypass the HEPA/adsorber filter unit close. These dampers are in series to provide required redundancy.

- Filter booster fan (CCRBF-21) starts and the associated isolation damper (F-1) opens and draws outside air through the HEPA/adsorber filter unit at a rate sufficient to pressurize the control room. The filter booster fan supplies the filtered air to the suction of the air conditioning unit fan (CCRF-21) where the filtered air is mixed with air being recirculated from the control room. If the filter booster fan (CCRBF-21) fails to start or trips, a flow switch will detect the failure and start the redundant filter booster fan (CCRBF-22) after a predetermined time delay.

- Air conditioning unit fan (CCRF-21) recirculates the mixture of filtered outside air and control room air. If the air conditioning unit fan (CCRF-21) fails to start or trips, a flow switch will detect the failure and a redundant fan (CCRCF-22) will start. The redundant fan will continue to recirculate control room air but will bypass the air conditioning unit.

<u>Incident 100% recirculation mode (mode 3) for the CRVS</u> is used for protection from smoke. In this mode, the CRVS is aligned for 100% recirculation of control room air through the air conditioning unit with no outside air makeup.

The original CRVS design was not required to meet single failure criteria but has been upgraded so that the active mechanical components needed for pressurization mode (mode 2) are redundant. To meet this requirement, the CRVS is divided into two trains as follows:

BASES

LCO (continued)

This LCO governs only those portions of the CRVS needed to ensure that the design basis single active failure criterion is met for automatic protection against airborne radiation using the filtered pressurization mode of operation (mode 2).

The LCO is modified by a Note allowing the control room boundary to be opened intermittently under administrative controls. For entry and exit through doors, the administrative control of the opening is performed by the person(s) entering or exiting the area. For other openings, these controls consist of stationing a dedicated individual at the opening who is in continuous communication with the control room. This individual will have a method to rapidly close the opening when a need for control room isolation is indicated.

Technical Requirements Manual (TRM) 3.9.A, "Decay Time," (Ref. 5) prevents any movement of recently irradiated fuel by prohibiting movement of any fuel in the reactor until 100 hours after reactor shutdown.

APPLICABILITY

In MODES 1, 2, 3 and 4, CRVS must be OPERABLE to control operator exposure during and following a DBA.

During movement of recently irradiated fuel assemblies, the CRVS must be OPERABLE to cope with the release from a fuel handling accident involving recently irradiated fuel. The CRVS is only required to be OPERABLE during fuel handling involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 100 hours), due to radioactive decay.

ACTIONS

A.1

When one CRVS train is inoperable, action must be taken to restore OPERABLE status within 7 days. In this Condition, the remaining OPERABLE CRVS train is adequate to perform the control room protection function. However, the overall reliability is reduced because a single failure in the OPERABLE CRVS train could result in loss of CRVS function. The 7 day Completion Time is based on the low probability of a DBA occurring during this time period, and ability of the remaining train to provide the required capability.

BASES

ACTIONS (continued)

B.1

When neither CRVS train is OPERABLE (which includes an inoperable control room boundary), action must be taken to restore at least one train to OPERABLE status within 72 hours. The 72 hour Completion Time is acceptable because of the low probability of a DBA occurring during this time period.

C.1 and C.2

If the inoperable CRVS train or control room boundary cannot be restored to OPERABLE status within the required Completion Time, the unit must be placed in a MODE that minimizes accident risk. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

D.1 and D.2

Reference 3 did not address exposure to control room operators resulting from fuel handling accidents when less than 100 hours of decay time have elapsed if the control room ventilation safety function is not met. Therefore, when only one CRVS train is OPERABLE during movement of recently irradiated fuel, action must be taken to immediately place the OPERABLE CRVS train in the pressurization mode. This action ensures that the remaining train is OPERABLE, that no failures preventing automatic actuation will occur, and that any active failure would be readily detected. An alternative to Required Action D.1 is to immediately suspend activities that could result in a release of radioactivity that might require isolation of the control room. This places the unit in a condition that minimizes risk. This does not preclude the movement of fuel to a safe position.

E.1

Reference 3 did not address exposure to control room operators resulting from fuel handling accidents when less than 100 hours of decay time have elapsed if the control room ventilation safety function is not met. Therefore, when neither CRVS train is OPERABLE during movement of recently irradiated fuel, action must be taken immediately to suspend activities that could result in a release of radioactivity that might enter the control room. This places the unit in a condition that minimizes accident risk. This does not preclude the movement of fuel to a safe position.

3.7 PLANT SYSTEMS

3.7.11 Spent Fuel Pit Water Level

LCO 3.7.11 The Spent Fuel Pit water level shall be ≥ 23 ft over the top of irradiated fuel assemblies seated in the storage racks.

APPLICABILITY: During movement of irradiated fuel assemblies in the Spent Fuel Pit.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Spent Fuel Pit water level not within limit.	A.1	- NOTE - LCO 3.0.3 is not applicable. Suspend movement of irradiated fuel assemblies in the Spent Fuel Pit.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.11.1	Verify the Spent Fuel Pit water level is ≥ 23 ft above the top of the irradiated fuel assemblies seated in the storage racks.	7 days

B 3.7 PLANT SYSTEMS

B 3.7.11 Spent Fuel Pit Water Level

BASES

BACKGROUND

The minimum water level in the spent fuel pit meets the assumptions of iodine decontamination factors following a fuel handling accident. The specified water level shields and minimizes the general area dose when the storage racks are filled to their maximum capacity. The water also provides shielding during the movement of spent fuel.

A general description of the spent fuel pit including the cooling and cleanup system is given in the UFSAR, Section 9.3 (Ref. 1). The assumptions of the fuel handling accident are given in References 2 and 3.

APPLICABLE SAFETY ANALYSES

The minimum water level in the spent fuel pit meets the assumptions of the fuel handling accident evaluated in Reference 3 when the radiological consequence analyses for Indian Point 2 were revised to demonstrate compliance with 10 CFR 50.67, Accident Source Term (Ref. 4). The radiological consequence analysis for a fuel handling accident in the fuel storage building assumes that a fuel assembly is dropped and damaged during refueling.

Activity released from the damaged assembly is released to the outside atmosphere through the fuel-handling building ventilation system to the plant vent. No credit is taken for removal of iodine by filters, nor is credit taken for isolation of release paths. The activity released from the damaged assembly is assumed to be released to the environment over a 2-hour period. These assumptions are consistent with the guidance provided in NRC Draft Guide (DG)-1081. The fuel assembly fission product inventory is based on the assumption that the subject fuel assembly has been operated at 1.7 times core average power (and thus has 1.7 times the average fuel assembly fission product inventory). The decay time used in the analysis is 100 hours. In accordance with this LCO, it is assumed that there is a minimum of 23 feet of water above the spent fuel racks. With this water depth, the decontamination factor (DF) of 500 specified by DG-1081 for elemental iodine would apply. The decontamination factor was reduced to 400 for conservatism because the fuel rod pressure may exceed the NRC DG-1081 assumption of 1200 psig (but would be less than 1500 psig). The decontamination factor for organic iodine and noble gases was 1.0.

BASES

ACTIONS (continued)

a safe position. This action effectively precludes the occurrence of a fuel handling accident. This does not preclude movement of a fuel assembly to a safe position.

If moving irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODES 1, 2, 3, and 4, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of irradiated fuel assemblies is not sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.7.11.1

This SR verifies sufficient spent fuel pit water is available in the event of a fuel handling accident. The water level in the spent fuel pit must be checked periodically. The 7 day Frequency is appropriate because the volume in the spent fuel pit is normally stable. Water level changes are controlled by plant procedures and are acceptable based on operating experience.

During refueling operations, the level in the spent fuel pit is in equilibrium with the refueling canal, and the level in the refueling cavity is checked daily in accordance with SR 3.9.6.1.

REFERENCES

1. UFSAR, Section 9.3.
2. UFSAR, Section 14.2.
3. Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Amendment No. 211 to Facility Operating License No. DPR-26, July 27, 2000.
4. 10 CFR 50.67.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Reference 2 also evaluated credible abnormal occurrences in accordance with ANSI/ANS-57.2-1983. This evaluation considered the effects of the following: a) a dropped fuel assembly or an assembly placed alongside a rack; b) a misloaded fuel assembly; and, c) abnormal heat loads. Reference 2 determined that the SFP will maintain a keff of ≤ 0.95 under the worst-case accident scenario if the SFP is filled with a soluble boron concentration of ≥ 1495 ppm.

NET-173-02, "Indian Point Unit 2 Spent Fuel Pool (SFP) Boron Dilution Analysis" (Ref. 3) evaluated postulated unplanned SFP boron dilution scenarios assuming an initial SFP boron concentration within the limits of LCO 3.7.12. The evaluation considered various scenarios by which the SFP boron concentration may be diluted and the time available before the minimum boron concentration necessary to ensure subcriticality for the non-accident condition (i.e. it is not assumed an assembly is misloaded concurrent with the Spent Fuel Pit dilution event). Reference 3 determined that an unplanned or inadvertent event that could dilute the SFP boron concentration from 2000 ppm to 786 ppm is not a credible event because of the low frequency of postulated initiating events and because the event would be readily detected and mitigated by plant personnel through alarms, flooding, and operator rounds through the SFP area.

References 2 and 3 are based on conservative projections of amount of Boraflex absorber panel degradation assumed in each sub-region. These projections are valid through the end of the year 2006. These compensatory measures for boraflex degradation in the SFP were evaluated by the NRC in Reference 4.

The concentration of dissolved boron in the spent fuel pit satisfies Criterion 2 of 10 CFR 50.36 (c)(2)(ii).

LCO

The Spent Fuel Pit boron concentration is required to be ≥ 2000 ppm. The specified concentration of dissolved boron in the Spent Fuel Pit preserves the assumptions used in the analyses of the potential critical accident scenarios as described in Reference 2. This concentration of dissolved boron is the minimum required concentration for fuel assembly storage and movement within the Spent Fuel Pit.

APPLICABILITY

This LCO applies whenever fuel assemblies are stored in the Spent Fuel Pit.

3.8 ELECTRICAL POWER SYSTEMS

3.8.1 AC Sources - Operating

LCO 3.8.1 The following AC electrical sources shall be OPERABLE:

a. Two qualified circuits between the offsite transmission network and the onsite AC Electrical Power Distribution System; and

b. Three diesel generators (DGs) capable of supplying the onsite power distribution subsystem(s).

- NOTE -

The automatic transfer function for the 6.9 kV buses shall be OPERABLE whenever the 138 kV offsite circuit is supplying 6.9 kV bus 5 and 6 and the Unit Auxiliary Transformer is supplying 6.9 kV bus 1, 2, 3 or 4.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

- NOTE -

LCO 3.0.4.b is not applicable to DGs or the 138 kV offsite circuit.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One offsite circuit inoperable.	A.1 Perform SR 3.8.1.1 for OPERABLE offsite circuit. AND	1 hour AND Once per 8 hours thereafter

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.6	Verify the fuel oil transfer system operates to automatically transfer fuel oil from the associated storage tank to the day tank.	92 days
SR 3.8.1.7	- NOTE - This Surveillance shall not normally be performed in MODE 1 or 2. However, this Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Verify manual transfer of AC power sources from the normal offsite circuit to the alternate offsite circuit.	24 months
SR 3.8.1.8	- NOTES - 1. This Surveillance shall not normally be performed in MODE 1 or 2. However, this Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. 2. Only required to be met if 138 kV offsite circuit is supplying 6.9 kV bus 5 and 6 and the Unit Auxiliary Transformer is supplying 6.9 kV bus 1, 2, 3 or 4. Verify automatic transfer of AC power for 6.9 kV buses 2 and 3 from the unit auxiliary transformer to 6.9 kV buses 5 and 6.	24 months

BASES

BACKGROUND (continued)

In the event of a loss of the 138 kV offsite circuit, the ESF electrical loads are automatically connected to the DGs in sufficient time to provide for safe reactor shutdown and to mitigate the consequences of a Design Basis Accident (DBA) such as a loss of coolant accident (LOCA).

Certain required unit loads are returned to service in a predetermined sequence in order to prevent overloading the DG in the process. Within 1 minute after the initiating signal is received, all loads needed to recover the unit or maintain it in a safe condition are returned to service.

Ratings for DGs 21, 22 and 23 are consistent with the requirements of Regulatory Guide 1.9 (Ref. 3). Each diesel generator consists of an Alco Model 16-251-E engine coupled to a Westinghouse 900 rpm, 3-phase, 60-cycle, 480 V generator. Each diesel generator has a capability of 1750 kW (continuous), 2300 kW for 1/2 hour in any 24 hour period, and 2100 kW for 2 hours in any 24 hour period. There is a sequential limitation whereby it is unacceptable to operate DGs for two hours at 2100 kW followed by operating at 2300 kW for a half hour. Any other combination of the above ratings is acceptable. The ESF loads that are powered from the 480 V ESF buses are listed in Reference 2.

APPLICABLE SAFETY ANALYSES

The initial conditions of DBA and transient analyses in the UFSAR, Chapter 6 (Ref. 4) and Chapter 14 (Ref. 5), assume ESF systems are OPERABLE. The AC electrical power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System (RCS), and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

The OPERABILITY of the AC electrical power sources is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This results in maintaining at least 2 of the 3 safeguards power trains energized from either onsite or offsite AC sources during accident conditions in the event of:

a. An assumed loss of all offsite power or all onsite AC power and

b. A worst case single failure.

The AC sources satisfy Criterion 3 of 10 CFR 50.36.

BASES

ACTIONS (continued)

A.1

To ensure a highly reliable power source remains with one offsite circuit inoperable, it is necessary to verify the OPERABILITY of the remaining required offsite circuit on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action not met. However, if a second required circuit fails SR 3.8.1.1, the second offsite circuit is inoperable, and Condition C, for two offsite circuits inoperable, is entered.

A.2

Required Action A.2, which applies only if the 13.8 kV offsite power circuit is being used to feed 6.9 kV buses 5 or 6 and the UAT is supplying 6.9 kV bus 1, 2, 3 or 4, prevents the automatic transfer of 6.9 kV buses 1, 2, 3, and 4 from the UAT to the 13.8 kV offsite power circuit after a unit trip. Transfer of buses 1, 2, 3, and 4 from the UAT to the 13.8 kV offsite power circuit could result in overloading the 13.8 kV/6.9 kV autotransformer. This requirement is not intended to preclude supplying 6.9 kV buses 1, 2, 3, and 4 using the 13.8 kV offsite circuit via the 13.8 kV/6.9 kV auto-transformers once sufficient loads have been stripped from 6.9 kV buses 1, 2, 3, and 4 to assure that the 13.8 kV/6.9 kV auto-transformer will not be overloaded. Automatic transfer of buses 1, 2, 3, and 4 can be disabled by placing 6.9 kV bus tie breaker control switches 1-5, 2-5, 3-6, and 4-6 in the "pull-out" position. These breaker control switches should be "tagged" in the pull-out position if this condition is expected to last more than one full shift.

Although the auto-transfer feature is normally disabled prior to placing the 13.8 kV offsite power circuit in service, a Completion Time of 1 hour ensures that the 13.8 kV circuit meets requirements for OPERABILITY promptly when the alternate offsite circuit is configured to support the response of ESF functions.

A.3

Required Action A.3, which only applies if the train will not be automatically powered from an offsite source, is intended to provide assurance that an event coincident with a single failure of the associated DG will not result in a complete loss of redundant required features. When one or more offsite sources are inoperable, a train may not be automatically powered from an

BASES

ACTIONS (continued)

In the event the inoperable DG is restored to OPERABLE status prior to completing either B.3.1 or B.3.2, the plant corrective action 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. 10), 24 hours is reasonable to confirm that the OPERABLE DGs 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 Distribution System. The 7 day Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

C.1 and C.2

Required Action C.1, which applies when two offsite circuits are inoperable, is intended to provide assurance that an event with a coincident single failure will not result in a complete loss of redundant required safety functions. The Completion Time for this failure of redundant required features is reduced to 12 hours from that allowed for one train without offsite power (Required Action A.3). The rationale for the reduction to 12 hours is that Regulatory Guide 1.93 (Ref. 6) allows a Completion Time of 24 hours for two required offsite circuits inoperable, based upon the assumption that three complete safeguards power trains are OPERABLE. When a redundant required feature is not OPERABLE, this assumption is not the case, and a shorter Completion Time of 12 hours is appropriate. These features are powered from redundant AC safety trains. This includes motor driven auxiliary feedwater pumps. Single train features, such as turbine driven auxiliary pumps, are not included as discussed in the Bases for Required Action A.3.

BASES

SURVEILLANCE REQUIREMENTS (*continued*)

checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are established by Regulatory Guide 1.137 (Ref. 8). This SR is for preventative maintenance. The presence of water does not necessarily represent failure of this SR, provided the accumulated water is removed during the performance of this Surveillance.

SR 3.8.1.6

This Surveillance demonstrates that each required fuel oil transfer pump operates and transfers fuel oil from its associated storage tank to its associated day tank. This is required to support continuous operation of standby power sources. This Surveillance provides assurance that the fuel oil transfer pump is OPERABLE, the fuel oil piping system is intact, the fuel delivery piping is not obstructed, and the controls and control systems for automatic fuel transfer systems are OPERABLE.

The IP2 design includes the following backup feature. If a fuel oil transfer pump fails to refill the day tank, one of the fuel oil transfer pumps associated with a different DG will receive an automatic starting signal and will fill the day tank for the affected DG via the common makeup line to all three diesel-generator fuel-oil day tanks. This backup feature is not required for DG OPERABILITY; however, the feature is tested because its existence is part of the justification for the 92 day SR Frequency. Therefore, the need for accelerated testing of the transfer function should be evaluated when this backup feature is out of service.

The Frequency for this SR is 92 days. The 92 day Frequency corresponds to the testing requirements for pumps as contained in the ASME Code, Section XI.

SR 3.8.1.7

Transfer of each offsite power supply from the 138 kV offsite circuit to the 13.8 kV offsite circuit demonstrates the OPERABILITY of the alternate circuit distribution network to power the shutdown loads. The 24 month Frequency of the Surveillance is based on engineering judgment, taking into consideration the unit 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 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

BASES

SURVEILLANCE REQUIREMENTS (continued)

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, unit safety systems. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g. post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced.

SR 3.8.1.8

Verification that 6.9 kV buses 2 and 3 will auto transfer (dead fast transfer) from the Unit Auxiliary Transformer (the main generator) to 6.9 kV buses 5 and 6 (the offsite circuit) following a loss of voltage on 6.9 kV buses 2 and 3 is needed to confirm the OPERABILITY of a function assumed to operate to provide offsite power to safeguards power train 2A/3A following a trip of the main generator. (Note that when the main generator trips on over-frequency, the transfer is blocked by an over-frequency transfer interrupt circuit provided for bus protection of out of phase transfer.)

An actual demonstration of this feature requires the tripping the main generator while the reactor is at power with the main generator supplying 6.9 kV buses 2 and 3. Credit may be taken for planned plant trips or for unplanned events that satisfy this SR. Other than planned plant trips or unplanned events, Note 1 specifies that this SR is not normally performed in MODE 1 or 2 because performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, unit safety systems. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g. post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced.

In lieu of actually initiating a circuit transfer, this SR may be satisfied by testing that adequately shows the capability of the transfer. This transfer testing may include any sequence of sequential, overlapping, or total steps so that the entire transfer sequence is verified.

BASES

SURVEILLANCE REQUIREMENTS (continued)

load and that safety analysis assumptions regarding ESF equipment time delays are not violated. Reference 2 provides a summary of the automatic loading of ESF buses.

The Frequency of 24 months is based on engineering judgment, taking into consideration operating experience that has shown that these components usually pass the SR. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note that specifies that load timers associated with equipment that has automatic initiation capability disabled are not required to be OPERABLE. This note is needed because these time delay relays affect the OPERABILITY of both the AC sources (offsite power and DG) and the specific load that the relay starts. If a timer fails to start a required load or if a timer starts the load later than assumed in the analysis, then the required load is not OPERABLE. If a timer starts the load outside the design interval (early or late), then the DG and offsite source are not OPERABLE because overlap of equipment starts may cause an offsite source to exceed limits for voltage or current or a DG to exceed limits for voltage, current or frequency. Therefore, when an individual load sequence timer is not OPERABLE, it is conservative to disable the automatic initiation capability of that component (and declare the specific component inoperable) rather than declare the associated DG and offsite circuit inoperable because of the following: the potential for adverse impact on the DG by simultaneous start of ESF equipment is eliminated; all other loads powered from the safeguards power train are available to respond to the event; and, the load with the inoperable timer remains available for a manual start after the one minute completion of the normal starting sequence.

If a load sequence timer is inoperable and the automatic initiation capability of that component has not been disabled, Condition D applies because both the associated DG and the 138 kV offsite circuit are inoperable until automatic initiation capability of the associated component has been disabled.

SR 3.8.1.12

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.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.13

This Surveillance demonstrates that the DG starting independence has not been compromised. Also, this Surveillance demonstrates that each engine can achieve proper speed within the specified time when the DGs are started simultaneously.

The 10 year Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3).

This SR is modified by two Notes. The reason for Note 1 is to minimize wear on the DG during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is to allow SR 3.8.1.12 to satisfy the requirements of this SR if SR 3.8.1.12 is performed with more than one safeguards power train concurrently.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. UFSAR, Chapter 8.
3. Regulatory Guide 1.9, Rev. 3, July 1993.
4. UFSAR, Chapter 6.
5. UFSAR, Chapter 14.
6. Regulatory Guide 1.93, Rev. 0, December 1974.
7. 10 CFR 50, Appendix A, GDC 18.
8. Regulatory Guide 1.137.
9. IEEE Standard 387-1995, IEEE Standard Criteria for Diesel-Generator Units Applied as Standby Power Supplies for Nuclear Power Generating Stations.
10. Generic Letter 84-15, July 2, 1984.

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
	A.2.1 Suspend CORE ALTERATIONS. AND A.2.2 Suspend movement of recently irradiated fuel assemblies. AND A.2.3 Suspend operations involving positive reactivity additions that could result in loss of required SDM or boron concentration. AND A.2.4 Initiate action to restore required offsite power circuit to OPERABLE status.	Immediately Immediately Immediately Immediately
B. One or more required DG inoperable.	B.1 Declare affected required feature(s) with no DG available inoperable. OR B.2.1 Suspend CORE ALTERATIONS. AND B.2.2 Suspend movement of recently irradiated fuel assemblies. AND	Immediately Immediately Immediately

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
	B.2.3 Suspend operations involving positive reactivity additions that could result in loss of required SDM or boron concentration.	Immediately
	AND	
	B.2.4 Initiate action to restore required DG to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.2.1	- NOTES - 1. The following SRs are required to be met but are not required to be performed: SR 3.8.1.3, SR 3.8.1.10, SR 3.8.1.11, and SR 3.8.1.12. 2. Portions of SR 3.8.1.12 regarding an actual or simulated ESF actuation signal are not required to be met.	
	For AC sources required to be OPERABLE, the SRs of Specification 3.8.1, "AC Sources - Operating," except SR 3.8.1.7, SR 3.8.1.8, SR 3.8.1.9, and SR 3.8.1.13, are applicable.	In accordance with applicable SRs

BASES

ACTIONS (continued)

A.2.1, A.2.2, A.2.3, and A.2.4

With the offsite circuit not available to all required trains, the option would still exist to declare all required features inoperable. Since this option may involve undesired administrative efforts, the allowance for sufficiently conservative actions is made. It is, therefore, required to suspend CORE ALTERATIONS, movement of recently irradiated fuel assemblies, and operations involving positive reactivity additions that could result in loss of required SDM (MODE 5) or boron concentration (MODE 6). Suspending positive reactivity additions that could result in failure to meet the minimum SDM or boron concentration limit is required to assure continued safe operation. Introduction of coolant inventory must be from sources that have a boron concentration greater than what would be required in the RCS for minimum SDM or refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation. Introduction of temperature changes including temperature increases when operating with a positive MTC must also be evaluated to ensure they do not result in a loss of required SDM.

Suspension of these activities does not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability or the occurrence of postulated events. It is further required to immediately initiate action to restore the required AC sources and to continue this action until restoration is accomplished in order to provide the necessary AC power to the unit safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required AC electrical power sources should be completed as quickly as possible in order to minimize the time during which the unit safety systems may be without sufficient power.

Pursuant to LCO 3.0.6, the Distribution System's ACTIONS would not be entered even if all AC sources to it are inoperable, resulting in de-energization. Therefore, the Required Actions of Condition A are modified by a Note to indicate that when Condition A is entered with no AC power to any required ESF bus, the ACTIONS for LCO 3.8.10 must be immediately entered. This Note allows Condition A to provide requirements for the loss of the offsite circuit, whether or not a train is de-energized. LCO 3.8.10 would provide the appropriate restrictions for the situation involving a de-energized bus.

BASES

ACTIONS (continued)

B.1

A DG would be considered inoperable if it could not support its associated safeguards power train. One OPERABLE DG and its associated safeguards power train may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS and fuel movement. By the allowance of the option to declare required features inoperable, with no DG available, appropriate restrictions will be implemented in accordance with the affected required features LCO's ACTIONS.

B.2.1, B.2.2, B.2.3 and B.2.4

When two DGs are required to be OPERABLE and one required DG is inoperable, the option would still exist to declare inoperable all required features supported by the inoperable DG. Since this option may involve undesired administrative efforts, the allowance for sufficiently conservative actions is made. Therefore, with one required DG inoperable, the option exists to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies, and operations involving positive reactivity additions.

With two required DGs inoperable, the minimum required diversity of AC power sources is not available to any required features. Although the option would still exist to declare all required features inoperable, the requirements imposed by the affected required features LCO's ACTIONS would be equivalent to the option provided by Required Actions B.2.1, B.2.2 and B.2.3. Therefore, with two required DGs inoperable, it is required to suspend CORE ALTERATIONS, movement of recently irradiated fuel assemblies, and operations involving positive reactivity additions.

With one required DG inoperable, when only one is required to be OPERABLE, the available options are equivalent to the situation described above for two inoperable DGs when two DGs are required. The additional restrictions on plant conditions for requiring only one DG provides ample time for operator action, in the event of a loss of offsite power, to manually restore decay heat removal capability.

With one or more required DGs inoperable, the Required Action to suspend positive reactivity additions does not preclude actions to maintain or increase reactor vessel inventory provided the required SDM is maintained. Additionally, Required Actions B.2.1, B.2.2 and B.2.3 do not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability or the occurrence of postulated events.

BASES

ACTIONS (continued)

Furthermore, even when Required Actions B.2.1, B.2.2 and B.2.3 are implemented, it is required to immediately initiate action to restore the required DG(s) and to continue this action until restoration is accomplished in order to provide the necessary AC power to the unit safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required AC electrical power sources should be completed as quickly as possible in order to minimize the time during which the unit safety systems may be without sufficient power.

SURVEILLANCE REQUIREMENTS

SR 3.8.2.1

SR 3.8.2.1 requires the SRs from LCO 3.8.1 that are necessary for ensuring the OPERABILITY of the AC sources in other than MODES 1, 2, 3, and 4. SR 3.8.1.7 is not required to be met since only one offsite circuit is required to be OPERABLE. SR 3.8.1.8 is not required because autotransfer from the Unit Auxiliary Transformer to an offsite source is not needed when the plant is not at power. SR 3.8.1.9 is not required to be met because the required OPERABLE DG(s) is not required to undergo periods of being synchronized to the offsite circuit. SR 3.8.1.13 is excepted because starting independence is not required with the DG(s) that is not required to be OPERABLE.

This SR is modified by two Notes. The reason for Note 1 is to preclude requiring the OPERABLE DG(s) from being paralleled with the offsite power network or otherwise rendered inoperable during performance of SRs, and to preclude deenergizing a required 480 V bus or disconnecting a required offsite circuit during performance of SRs. With limited AC sources available, a single event could compromise both the required circuit and the DG. It is the intent that these SRs must still be capable of being met, but actual performance is not required during periods when the DG and offsite circuit is required to be OPERABLE. Refer to the corresponding Bases for LCO 3.8.1 for a discussion of each SR. Note 2 states that portions of SR 3.8.1.12 are not required to be met. The SR demonstrates the DG response to an ECCS signal (either alone or in conjunction with a loss-of-power signal). This is consistent with the ECCS instrumentation requirements that do not require the ECCS signals when the ECCS System is not required to be OPERABLE per LCO 3.5.3, "ECCS-Shutdown."

BASES

BACKGROUND (Continued)

Each of the three DG fuel oil storage tanks is provided with a motor-driven transfer pump mounted in a manhole opening above oil level. This pump is used to transfer fuel oil from the storage tank to the 175 gallon day tank supporting each DG. A decrease in day tank level to approximately 115 gallons (65%) will start the transfer pump in the corresponding DG fuel oil storage tank and run until the day tank is at approximately 158 gallons (90%). This process ensures that the day tank always contains sufficient fuel to support approximately 53 minutes of DG operation. If pump 21 fails to refill its associated day tank, transfer pump 22 will receive an automatic starting signal as a backup to the primary pump. In a similar manner, transfer pump 22 receives an automatic starting signal on low level in the day tank for diesel 22 and is backed up by transfer pump 23. Transfer pump 23 starts on low level in the day tank for diesel generator 23 and is backed up by transfer pump 21.

If the DGs require fuel oil from the fuel oil reserve tank(s), the fuel oil will be transported by truck to the DG fuel oil storage tanks. A truck with appropriate hose connections and capable of transporting oil is available either on site or at the Buchanan Substation. Commercial oil supplies and trucking facilities are also available in the vicinity of the plant.

For proper operation of the standby DGs, it is necessary to ensure the proper quality of the fuel oil. Regulatory Guide 1.137 (Ref. 2) addresses the recommended fuel oil practices as supplemented by ANSI N195 (Ref. 4). The fuel oil properties governed by these SRs are the water and sediment content, the viscosity, specific gravity (or API gravity), and impurity level. Requirements for DG fuel oil testing methodology, frequency, and acceptance criteria are maintained in the program required by Technical Specification 5.5.11, Diesel Fuel Oil Testing Program.

The DG lubrication system is designed to provide sufficient lubrication to permit proper operation of its associated DG under all loading conditions. The system is required to circulate the lube oil to the diesel engine working surfaces and to remove excess heat generated by friction during operation. Administrative controls ensure that the combination of the lube oil in the engine oil sump and maintained in onsite storage is sufficient to support 7 days of continuous operation of all three DGs. This supply is sufficient to allow operators to replenish the lube oil from offsite sources.

BASES

BACKGROUND (continued)

Each emergency diesel is automatically started by two redundant air motors. Each DG has a 53-ft^3 air storage tank and compressor system powered by a 480-V motor. The piping and the electrical services are arranged so that manual transfer between units is possible. The capability exists to cross-connect a single DG air compressor to more than one DG air receiver, via manual air tie valves. However, to ensure that the OPERABILITY of two of the three DGs is maintained in the event of a single failure, administrative controls are in-place to require an operator to be stationed within the DG Building, whenever any of the starting air tie valves are opened. Each air receiver has sufficient storage for four normal starts. However, all starting air will be consumed during a failed start attempt.

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Chapter 14 (Ref. 3), assume Engineered Safety Feature (ESF) systems are OPERABLE. The DGs are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that fuel, Reactor Coolant System and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

Since diesel fuel oil and the air start subsystem support the operation of the standby AC power sources, they satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The basis for a minimum volume of diesel fuel oil of 48,000 gallons (i.e. 6334 usable gallons in each of the three DG fuel oil storage tanks and 29,000 gallons in the DG fuel oil reserve) is to provide for operation of the minimum required engineered safeguards on emergency diesel power for a period of at least 168 hours. If only two of the three DG fuel oil storage tanks are available, the total remaining fuel oil in storage is sufficient to provide for operation of two DGs with recirculation loads for a period of at least 139 hours. It is also required to meet specific standards for quality. This requirement, in conjunction with an ability to obtain replacement supplies within 7 days, supports the availability of DGs required to shut down the reactor and to maintain it in a safe condition for an anticipated operational occurrence (AOO) or a postulated DBA with loss of offsite power.

BASES

LCO (Continued)

In MODES 5 and 6, LCO requirements for DG fuel oil are relaxed in recognition that reduced DG loading required to respond to events in MODES 5 and 6 significantly reduces the amount of fuel oil required in the DG fuel oil storage tanks. Therefore, the LCO requires a total of 6334 gallons of fuel oil in the tanks associated with the DGs that are required to be OPERABLE. This fuel may be stored in one tank associated with an OPERABLE DG or proportioned between the tanks associated with OPERABLE DGs. DG day tank fuel requirements, as well as transfer capability from the storage tank to the day tank, are addressed in LCO 3.8.1, "AC Sources - Operating," and LCO 3.8.2, "AC Sources - Shutdown."

The starting air system is required to have a minimum capacity for four successive normal DG starts without recharging the air start receivers.

APPLICABILITY

The AC sources (LCO 3.8.1 and LCO 3.8.2) are required to ensure the availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an AOO or a postulated DBA. Since stored diesel fuel oil and the starting air subsystem support LCO 3.8.1 and LCO 3.8.2, stored diesel fuel oil and starting air are required to be within limits when the associated DG is required to be OPERABLE.

ACTIONS

The ACTIONS Table is modified by a Note indicating that separate Condition entry is allowed for each DG. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable DG subsystem. Complying with the Required Actions for one inoperable DG subsystem may allow for continued operation, and subsequent inoperable DG subsystem(s) are governed by separate Condition entry and application of associated Required Actions.

A.1

In this Condition, the requirements of SR 3.8.3.2.a are not met for one or more DG fuel oil storage tanks. This means that replenishment of DG fuel oil from the reserve storage tanks will be needed in less time than assumed in the UFSAR (Ref. 1). Therefore, the DG(s) associated with the DG fuel oil storage tank(s) not within limits must be declared inoperable within 2 hours because replenishment of the DG fuel oil storage tank requires that fuel be transported from the DG fuel oil reserve by truck and the volume of fuel oil remaining in the DG fuel oil storage tank may not be sufficient to allow continuous DG operation while the fuel transfer is planned and conducted under accident conditions.

BASES

ACTIONS (continued)

This Condition is preceded by a Note stating that Condition A is applicable only in MODES 1, 2, 3 and 4. This Note provides recognition that reduced DG loading required to respond to events in MODES 5 and 6 significantly reduces the amount of fuel oil required in the DG fuel oil storage tanks when in these MODES.

B.1

In this Condition, the requirements of SR 3.8.3.2.b are not met. With less than the total required minimum fuel oil in one or more DG fuel oil storage tanks, the two DGs required to be OPERABLE in MODES 5 and 6 and during movement of recently irradiated fuel may not have sufficient fuel oil to support continuous operation while a fuel transfer from the offsite DG fuel oil reserve or from another offsite source is planned and conducted under accident conditions.

This Condition requires that all DGs be declared inoperable immediately because minimum fuel oil level requirements in SR 3.8.3.2.b is a Condition of OPERABILITY of all DGs when in the specified MODES.

This Condition is preceded by a Note stating that Condition B is applicable only in MODES 5 and 6. This Note provides recognition that reduced DG loading required to respond to events in MODES 5 and 6 significantly reduces the amount of fuel oil required in the DG fuel oil storage tanks when in these MODES.

C.1

In this Condition, the requirements of SR 3.8.3.1 are not met and the fuel oil remaining in the DG fuel oil reserve is not sufficient to operate 2 of the 3 DGs at minimum safeguards load for 7 days. Therefore, all 3 DGs are declared inoperable within 2 hours.

This Condition is preceded by a Note stating that Condition C is applicable only in MODES 1, 2, 3 and 4 because the DG fuel oil reserve is required to be available only in these MODES. This Note provides recognition that reduced DG loading required to respond to events in MODES 5 and 6 and when moving irradiated fuel and, therefore, significantly reduces the amount of fuel oil required when in these MODES.

BASES

ACTIONS (continued)

D.1

This Condition is entered as a result of a failure to meet the acceptance criterion for total particulate concentration of the fuel oil in the DG fuel oil storage tanks and/or the DG fuel oil reserve storage tanks is not within the allowable value in Technical Specification 5.5.11, Diesel Fuel Oil Testing Program, during periodic verifications required by SR 3.8.3.3 and SR 3.8.3.4. Normally, trending of particulate levels allows sufficient time to correct high particulate levels prior to reaching the limit of acceptability. Poor sample procedures (bottom sampling), contaminated sampling equipment, and errors in laboratory analysis can produce failures that do not follow a trend. Since the presence of particulates does not mean failure of the fuel oil to burn properly in the diesel engine, and particulate concentration is unlikely to change significantly between Surveillance Frequency intervals, and proper engine performance has been recently demonstrated (within 31 days), it is prudent to allow a brief period prior to declaring the associated DG inoperable. The Completion Time to restore particulate levels to within required limits is 7 days for DG fuel oil storage tanks and 30 days for reserve storage tanks. These Completion Times allow for further evaluation, resampling and re-analysis of the DG fuel oil and recognize the time that may be required to restore parameters to within limits.

This Condition is preceded by a Note that clarifies that this Condition applies to the reserve fuel oil storage tanks only in MODES 1, 2, 3 and 4.

E.1

New fuel oil may be added to the DG fuel oil storage tanks or the reserve storage tanks before results of samples of this new fuel oil are available. If the properties of new fuel oil are determined not to be within the requirements established by Technical Specification 5.5.11, "Diesel Fuel Oil Testing Program," after the fuel oil has been added to the DG fuel oil storage tanks or the reserve storage tanks, then the oil in the affected storage tank(s) must be confirmed to be within the limits established by Technical Specification 5.5.11. A Completion Time of 30 days is permitted to confirm and/or restore the DG fuel oil storage tanks to within the limits of Technical Specification 5.5.11. A Completion Time of 60 days is permitted to confirm and/or restore the DG fuel oil reserve tanks to within the limits of Technical Specification 5.5.11.

BASES

ACTIONS (continued)

F.1

With starting air receiver pressure < 250 psig, sufficient capacity for four successive DG start attempts does not exist. However, as long as the receiver pressure is ≥ 90 psig, there is adequate capacity for at least one normal start, and the DG can be considered OPERABLE while the air receiver pressure is restored to the required limit. A period of 48 hours is considered sufficient to complete restoration to the required pressure prior to declaring the DG inoperable. This period is acceptable based on the remaining air start capacity, the fact that most DG starts are accomplished on the first attempt, and the low probability of an event during this brief period. Entry into Condition F is not required when air receiver pressure is less than required limits while the DG is operating following a successful start.

G.1

With a Required Action and associated Completion Time not met, or one or more DG's fuel oil or starting air subsystem is not within limits for reasons other than addressed by Conditions A through F, the associated DG may be incapable of performing its intended function and must be immediately declared inoperable.

SURVEILLANCE REQUIREMENTS

SR 3.8.3.1

This SR provides verification that there is an adequate inventory of fuel oil in the DG fuel oil reserve to support 2 DGs at minimum safeguards load for 7 days assuming requirements for the DG fuel oil storage tanks and day tanks are met. The 7 day duration with 2 of the 3 DGs at minimum safeguards load is sufficient to place the unit in a safe shutdown condition and to bring in replenishment fuel from a commercial source.

This SR is modified by a Note that requires this SR to be met only when in MODES 1, 2, 3 or 4. The requirements for DG fuel oil are relaxed in recognition that in MODES 5 and 6 the reduced DG loading required to respond to events significantly reduces the amount of fuel oil required in the DG fuel oil storage tanks.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The 24 hour Frequency is needed because the DG fuel oil reserve is stored in fuel oil tanks that support the operation of gas turbine peaking units. This warrants frequent verification that required offsite DG fuel oil reserve volume is being maintained. Additionally, the DG fuel oil reserve includes oil designated for the exclusive use of Indian Point 3 and the IP3 UFSAR and the IP3 Technical Specifications require verification of the DG fuel oil reserve every 24 hours.

SR 3.8.3.2

SR 3.8.3.2.a provides verification when in MODES 1, 2, 3, and 4, that there is an adequate inventory of fuel oil in the DG fuel oil storage tanks to support at least 73 hours of operation of minimum safeguards equipment when all three DG fuel oil storage tanks are available or 45 hours of operation of minimum safeguards equipment when any two of the DG fuel oil storage tanks are available (Ref. 1). The 45 hour period of DG operation is sufficient time for a fuel transfer (from the fuel oil reserve or an offsite source) to be planned and conducted under accident conditions.

SR 3.8.3.2.b provides verification when in MODES 5 and 6 that the minimum required fuel oil for operation in these MODES is available in one or more DG fuel oil storage tanks. The minimum required volume of fuel oil takes into account the reduced DG loading required to respond to events in MODES 5 and 6 is sufficient to support the two DGs required to be operable in MODES 5 and 6 while a fuel transfer from the offsite DG fuel oil reserve or from another offsite source is planned and conducted under accident conditions.

This minimum volume required by SR 3.8.3.2.a and SR 3.8.3.2.b is the usable volume and does not include allowances for fuel not usable due to the fuel oil transfer pump cutoff switch (approximately 438 gallons). Additionally, an allowance must be made for instrument accuracy depending on the method used to determine tank volume. These adjustments must be made for each tank for SR 3.8.3.2.b if the required volume is found in more than one DG fuel oil storage tank.

The 31 day Frequency is adequate to ensure that a sufficient supply of fuel oil is available, since low level alarms are provided and unit operators would be aware of any large uses of fuel oil during this period.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.3.3 and SR 3.8.3.4

SR 3.8.3.3 requires that fuel oil properties of new and stored fuel oil in the DG fuel oil storage tanks are tested and maintained in accordance with Technical Specification 5.5.11, " Diesel Fuel Oil Testing Program."

SR 3.8.3.4 requires that fuel oil properties of new and stored fuel oil in the reserve storage tank(s) are within limits specified in Technical Specification 5.5.11. SR 3.8.3.4 is modified by a Note that requires this SR to be met only when in MODES 1, 2, 3 or 4 because the fuel oil in the reserve storage tank(s) is required only when in those MODES.

These Surveillances verify that the properties of new and stored fuel oil meet the acceptance criteria established by Technical Specification 5.5.11, "Diesel Fuel Oil Testing Program." Sampling and testing requirements for the performance of diesel fuel oil testing in accordance with applicable ASTM Standards are specified in the administrative program developed to ensure that Technical Specification 5.5.11 is met.

As required by Technical Specification 5.5.11, new fuel oil is sampled prior to addition to the DG fuel oil storage tanks and stored fuel oil is periodically sampled from the DG fuel oil storage tanks. Requirements and acceptance criteria for fuel oil are divided into 3 parts as follows:

a) tests of the sample of new fuel and acceptance criteria that must be met prior to adding the new fuel to the DG fuel oil storage tanks;

b) tests of the sample of new fuel that may be completed after the fuel is added to the DG fuel oil storage tanks; and,

c) tests of the fuel oil stored in the DG fuel oil storage tanks.

These tests are a means of determining whether new fuel oil is of the appropriate grade and has not been contaminated with substances that would have an immediate, detrimental impact on diesel engine combustion. If results from these tests are within acceptable limits, the fuel oil may be added to the storage tanks without concern for contaminating the entire volume of fuel oil in the storage tanks. These tests are to be conducted prior to adding the new fuel to the storage tank(s), but in no case is the time between receipt of new fuel and conducting the tests to exceed 31 days. The tests, limits, and applicable ASTM Standards are performed in accordance with the administrative program developed to ensure that Technical Specification 5.5.11 is met.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The 31 day Frequency takes into account the capacity, capability, redundancy, and diversity of the AC sources and other indications available in the control room, including alarms, to alert the operator to below normal air start pressure.

SR 3.8.3.6

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel storage tanks once every 31 days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, and contaminated fuel oil, and from breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are consistent with Regulatory Guide 1.137 (Ref. 2). This SR is for preventive maintenance. Unless the volume of water is sufficient that it could impact DG OPERABILITY, presence of water does not necessarily represent failure of this SR, provided the accumulated water is removed within 7 days of performance of the Surveillance.

REFERENCES

1. UFSAR, Section 8.2.
2. Regulatory Guide 1.137.
3. UFSAR, Chapter 14.
4. ANSI N195-1976, Appendix B.

BASES

BACKGROUND (continued)

The preferred and alternate sources of DC control power for the breakers and DGs are:

Transfer Switch	Associated 480 V Bus	Preferred Source	Alternate Source
EDD1	6A	PPNL #24	PPNL #22
EDD2	2A	PPNL #22	PPNL #24
EDD3	3A	PPNL #23	PPNL #21
EDD4	5A	PPNL #21	PPNL #23
EDD5	DG-21	PPNL #21	PPNL #23
EDD6	DG-22	PPNL #23	PPNL #22
EDD7	DG-23	PPNL #24	PPNL #22

The DC electrical power subsystems 21, 22, 23 and 24 also provide DC electrical power to the static inverters which supply power to the 118 VAC instrument buses. Each of the four DC electrical power subsystems supports one of the four Reactor Protection System (RPS) Instrumentation channels and one of the four Engineered Safety Features Actuation System (ESFAS) Instrumentation channels. DC electrical power subsystems 21 and 22 each support one of the two trains of RPS Instrumentation actuation logic and one of the two trains of ESFAS Instrumentation actuation logic. Electrical distribution, including DC Sources, is described in the UFSAR (Ref. 4).

During normal operation, the 125 VDC load is powered from the battery chargers with the batteries floating on the system. In case of loss of normal power to the battery charger, the DC load is automatically powered from the station batteries.

The DC power distribution system is described in more detail in Bases for LCO 3.8.9, "Distribution Systems - Operating," and LCO 3.8.10, "Distribution Systems - Shutdown."

Each 125 VDC battery is separately housed in a ventilated room apart from its charger and power panels. Each subsystem is separated electrically from the other subsystem to ensure that a single failure in one subsystem does not cause a failure in a redundant subsystem. There is no sharing between redundant subsystems, such as batteries, battery chargers, or power panels.

Each battery has adequate storage capacity to meet the duty cycle(s) discussed in the UFSAR, Chapter 8 (Ref 4). The battery is designed with additional capacity above that required by the design duty cycle to allow for temperature variations and other factors.

BASES

ACTIONS (continued)

Required Action A.2.3 limits the restoration time for the inoperable battery charger to 7 days. This action is applicable if an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage has been used (e.g., balance of plant non-Class 1E battery charger). The 7 day Completion Time reflects a reasonable time to effect restoration of the qualified battery charger to OPERABLE status.

B.1.1, B.1.2, B.2 and B.3

Condition B applies when one subsystem's battery and/or charger is inoperable and the plant is not in Condition A for an inoperable battery charger in any other DC electrical power subsystem.

Each DC electrical power subsystem supplies DC control power for the associated 480 V ESF switchgear and an associated DG and supplies a static inverter associated with one of the four 118 VAC instrument buses. However, if any of the four DC electrical power subsystems (i.e., battery and/or charger) fail to maintain the associated DC power panel above the required voltage, the IP2 design provides for the automatic transfer of both DC control power and the vital instrument bus to an alternate source of power.

When a DC electrical power subsystem is inoperable for reasons other than Condition A or if the election is made to enter Condition B for an inoperable battery charger, Required Actions B.1.1 and B.1.2, require verification by administrative means that DC control power supplied by the inoperable battery and/or charger is either being supplied by the alternate source or that the automatic transfer switch that will cause the transfer to the alternate source is OPERABLE. Additionally, Required Action B.2 requires verification that inverters associated with all other DC electrical power subsystems are OPERABLE. This ensures that requirements in LCO 3.8.7, "Inverters - Operating," are met if the inoperable battery and/or changer have caused the associated static inverter to transfer to an alternate source. This Required Action also recognizes there is increased potential that the static inverter will transfer to the alternate source during an accident or transient. The 2 hour Completion Time is based on Regulatory Guide 1.93 (Ref. 6) and reflects a reasonable time to assess unit status as a function of the inoperable DC electrical power subsystem and, if alternate sources of power for DC control power and the static inverter are not available, to initiate an orderly and safe unit shutdown. Required Action B.3 requires that an inoperable subsystem (i.e. battery and/or charger) be restored within

BASES

SURVEILLANCE REQUIREMENTS (continued)

The reason for Note 2 is that performing the Surveillance would perturb the electrical distribution system and challenge safety systems. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow portions of the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g. post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1 or 2. Risk insights or deterministic methods may be used for the assessment.

SR 3.8.4.4

This SR verifies that the alternate source of DC control power will be connected immediately if the required battery and/or charger does not maintain the associated DC power panel above the required minimum voltage needed to support DC control power. This SR also confirms that DC control power will transfer back to the preferred source when preferred source voltage is restored. Specifically, the DC control power transfer switch will function as follows:

a. Transfers from the preferred source to the alternate source when the preferred source is < 100 VDC and the alternate source > 112.5 VDC; and

b. Transfers from the alternate source to the preferred source when the preferred source is > 112.5 VDC.

OPERABILITY of this feature is needed only to justify a 24 hour Completion Time for restoration of an inoperable battery and/or charger. Therefore, this SR is modified by a NOTE that this SR is not required to be met unless needed to satisfy requirements of Required Action B.1.2 when a battery and/or charger is inoperable.

BASES

APPLICABLE SAFETY ANALYSES (continued)

pressure boundary, reactor coolant temperature and pressure, and the corresponding stresses result in the probabilities of occurrence being significantly reduced or eliminated, and in minimal consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCO for required systems.

The shutdown Technical Specification requirements are designed to ensure that the unit has the capability to mitigate the consequences of certain postulated accidents. Worst case Design Basis Accidents which are analyzed for operating MODES are generally viewed not to be a significant concern during shutdown MODES due to the lower energies involved. The Technical specifications therefore require a lesser complement of electrical equipment to be available during shutdown than is required during operating MODES. More recent work completed on the potential risks associated with shutdown, however, have found significant risk associated with certain shutdown evolutions. As a result, in addition to the requirements established in the Technical Specifications, the industry has adopted NUMARC 91-06, "Guidelines for Industry Actions to Assess Shutdown Management," as an industry initiative to manage shutdown tasks and associated electrical support to maintain risk at an acceptable low level. This may require the availability of additional equipment beyond that required by the shutdown Technical Specifications.

The DC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The DC electrical power subsystems, each required subsystem consisting of one battery, one battery charger per battery, and the corresponding control equipment and interconnecting cabling within the train, are required to be OPERABLE to support required trains of the distribution systems required OPERABLE by LCO 3.8.10, "Distribution Systems - Shutdown." This ensures the availability of sufficient DC electrical power sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents involving handling recently irradiated fuel). DC subsystems may be cross connected in MODES 5 and 6.

APPLICABILITY

The DC electrical power sources required to be OPERABLE in MODES 5 and 6, and during movement of recently irradiated fuel assemblies, provide assurance that:

BASES

ACTIONS (continued)

concentration greater than what would be required in the RCS for minimum SDM or refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation. Introduction of temperature changes including temperature increases when operating with a positive MTC must also be evaluated to ensure they do not result in a loss of required SDM.

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required DC electrical power subsystems and to continue this action until restoration is accomplished in order to provide the necessary DC electrical power to the unit safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required DC electrical power subsystems should be completed as quickly as possible in order to minimize the time during which the unit safety systems may be without sufficient power.

SURVEILLANCE REQUIREMENTS

SR 3.8.5.1

SR 3.8.5.1 requires performance of all Surveillances required by SR 3.8.4.1 through SR 3.8.4.3. Therefore, see the corresponding Bases for LCO 3.8.4 for a discussion of each SR.

This SR is modified by a Note. The reason for the Note is to preclude requiring the OPERABLE DC sources from being discharged below their capability to provide the required power supply or otherwise rendered inoperable during the performance of SRs. It is the intent that these SRs must still be capable of being met, but actual performance is not required.

REFERENCES

1. UFSAR, Chapter 14.

2. Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Amendment No. 211 to Facility Operating License No. DPR-26, July 27, 2000.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Battery parameters satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Battery parameters must remain within acceptable limits to ensure availability of the required DC power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence or a postulated DBA. Battery parameter limits are conservatively established, allowing continued DC electrical system function even with limits not met. Additional preventative maintenance, testing, and monitoring performed in accordance with the IP2 Battery Monitoring and Maintenance Program is conducted as specified in Specification 5.5.15.

APPLICABILITY

The battery parameters are required solely for the support of the associated DC electrical power subsystems. Therefore, battery parameter limits are only required when the DC power source is required to be OPERABLE. Refer to the Applicability discussion in Bases for LCO 3.8.4 and LCO 3.8.5.

ACTIONS

A.1, A.2, and A.3

With one or more cells in a battery < 2.07 V, the battery is degraded. Within 2 hours verification of the required battery charger OPERABILITY is made by monitoring the battery terminal voltage (SR 3.8.4.1) and of the overall battery state of charge by monitoring the battery float charge current (SR 3.8.6.1). This assures that there is still sufficient battery capacity to perform the intended function. Therefore, the affected battery is not required to be considered inoperable solely as a result of one or more cells in one or more batteries < 2.07 V, and continued operation is permitted for a limited period up to 24 hours.

Since the Required Actions only specify "perform," a failure of SR 3.8.4.1 or SR 3.8.6.1 acceptance criteria does not result in this Required Action not being met. However, if one of the SRs is failed, then the appropriate Condition(s) are entered depending on the cause of the failures. If SR 3.8.6.1 is failed then Condition F may be applicable.

BASES

ACTIONS (continued)

Since Required Action B.1 only specifies "perform," a failure of SR 3.8.4.1 acceptance criteria does not result in the Required Action not being met. However, if SR 3.8.4.1 is failed, then LCO 3.8.4, Condtion A, may be applicable.

C.1, C.2, and C.3

With one battery with one or more cells electrolyte level above the top of the plates, but below the minimum established design limits, the battery still retains sufficient capacity to perform the intended function. Therefore, the affected battery is not required to be considered inoperable solely as a result of electrolyte level not met. Required Action C.3 requires that the minimum established design limits for electrolyte level be re-established within 31 days.

With electrolyte level below the top of the plates, there is a potential for dryout and plate degradation. Required Actions C.1 and C.2 address this condition and are only applicable if electrolyte level is below the top of the plates. If the level is below the top of the plates, Required Action C.1 requires that level is required to be restored to above the top of the plates within 8 hours and Required Action C.2 requires that a visual inspection verify that there is no leakage from the battery.

Note that the program required by Technical Specification 5.5.15 may establish additional requirements from IEEE Standard 450-1995 (Ref. 3) for recovery from Condition A (e.g., Annex D Reference 3 could require an equalizing charge and testing in accordance with manufacturer's recommendation following the restoration of the electrolyte level to above the top of the plates).

D.1

With one battery with pilot cell temperature less than the minimum established design limits, 12 hours is allowed to restore the temperature to within limits before the battery must be declared inoperable. A battery temperature below the design minimum results in a battery capacity less than assumed in the battery sizing calculation. This Condition is acceptable for 12 hours because the Condition is limited to one DC subsystem and the battery remains functional although with reduced capacity.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.7 Inverters - Operating

BASES

BACKGROUND

The inverters are the preferred source of power for the 118 VAC instrument buses because of the stability and reliability they achieve. The function of the inverter is to provide AC electrical power to the 118 VAC instrument buses. Each inverter receives power from a different DC Power Panel. The station battery provides an uninterruptible power source for the instrumentation and controls for the Reactor Protection System (RPS) and the Engineered Safety Feature Actuation System (ESFAS). Specific details on inverters and their operating characteristics are found in the UFSAR, Chapter 8 (Ref. 1).

In addition to the normal DC power source for the inverter, each inverter has an associated step-down transformer that is used as alternate input power supply (118 VAC nominal) to the instrument buses. The alternate power supply is used to synchronize the inverter output to the auxiliary electrical system and to provide continuity of power to the vital 118 VAC loads in the unlikely event of an inverter failure. Each alternate power supply can be used to support the 118 VAC loads via the inverter internal static transfer switch or via an external manual bypass switch. Using either of these methods, the alternate input power source to each inverter is the same step-down transformer.

Power is supplied to the instrument buses from the DC source via the inverter or from the step-down transformer as follows:

Inverter	Normal Source	Alternate Power Supply
21	DCPP 21	MCC 26A
22	DCPP 22	MCC 24A
23	DCPP 23	MCC 29A
24	DCPP 24	MCC 27A

In the event of a loss of DC power to the inverter, the inverter's internal static transfer switch will automatically transfer the 118 VAC loads to the alternate power supply. Additionally, each 118 VAC instrument bus has a manual transfer switch mounted in a separate enclosure that can bypass the static transfer switch and provide backup power from the alternate power supply directly to the 118 VAC buses.

BASES

BACKGROUND (continued)

To ensure that a single failure of an emergency diesel-generator will not result in the unavailability of more than one 118 VAC system, the normal and backup supplies for three of the instrument buses 21, 22, and 24 are fed from the associated emergency diesel-generator. Instrument bus 23 is normally fed from DG 22 with a backup supply from DG 21, providing diverse sources to prevent the potential loss of two instrument buses due to loss of a single DG.

The alternate power supply to the instrument busses will be interrupted during accident conditions involving a safety injection actuation (with or without loss of offsite power) and during a loss of offsite power. The alternate power supply will be available after the emergency diesel generator re-energizes the associated 480 V MCC. Depending on the event and the inverter, operator action may be needed to re-energize the alternate power supply. Therefore, operator action may be required to re-energize an 118 V instrument bus during an SI or a LOOP if the associated inverter is being bypassed or fails during the event.

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Chapter 14 (Ref. 2), assume Engineered Safety Feature systems are OPERABLE. The inverters are designed to provide the required capacity, capability, redundancy, and reliability to ensure the availability of necessary power to the RPS and ESFAS instrumentation and controls so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

The OPERABILITY of the inverters is consistent with the initial assumptions of the accident analyses and is based on meeting the design basis of the unit. This includes maintaining required 118 VAC instrument buses OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite AC electrical power or all onsite AC electrical power and

b. A worst case single failure.

Inverters are a part of the distribution system and, as such, satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO The inverters ensure the availability of AC electrical power for the systems instrumentation required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA.

Maintaining the required inverters OPERABLE ensures that the redundancy incorporated into the design of the RPS and ESFAS instrumentation and controls is maintained. The four inverters ensure an uninterruptible supply of AC electrical power to the 118 VAC instrument buses even if the 480 V safety buses are de-energized.

OPERABLE inverters require the associated 118 VAC instrument bus to be powered by the inverter with output voltage and frequency within tolerances, and power input to the inverter from a station battery.

APPLICABILITY

The inverters are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients and

b. Adequate core cooling is provided, and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

Inverter requirements for MODES 5 and 6 are covered in the Bases for LCO 3.8.8, "Inverters - Shutdown."

ACTIONS

With an inverter inoperable, its associated 118 VAC instrument bus will be inoperable until the bus is re-energized from its associated alternate power supply. For this reason, a Note to the ACTIONS requires entry into the Conditions and Required Actions of LCO 3.8.9, "Distribution Systems - Operating," until the 118 VAC instrument bus is energized. The Required Actions of LCO 3.8.9 will ensure that the 118 VAC instrument bus is re-energized within 2 hours.

BASES

ACTIONS (continued)

A.1

With an inverter inoperable, its associated 118 VAC instrument bus must be powered from its associated alternate power supply. However, the alternate power supply may be supported by MCCs that are stripped and not automatically re-connected following a SI signal or a LOOP. Therefore, operator action may be required to re-energize an 118 V instrument bus during an SI or a LOOP if the associated inverter is being bypassed or fails during the event.

Required Action A.1 is necessary when the backup power supply is being used in place of any of the inverters because the associated 118 VAC instrument bus may be de-energized following an SI signal or LOOP. Therefore, a loss of safety function could exist for any function powered from the 118 VAC instrument bus if that function requires power to perform the required safety function if the redundant required feature is inoperable. To compensate for a potential loss of safety function, Required Action A.1 requires declaring required feature(s) supported by associated inverter inoperable when its required redundant feature(s) is inoperable. As specified in the associated Note, this requirement only applies to feature(s) that require power to perform the required safety function (e.g., automatic actuation of core spray, Regulatory Guide 1.97 instrumentation, etc.). The 2 hour Completion Time is consistent with LCO 3.8.9, "Distribution Systems - Operating," requirements for an inoperable 118 VAC instrument bus.

A.2

Required Action A.2 is necessary because the inverter, as an uninterruptible power source to the 118 VAC instrument bus, is the preferred source for powering instrumentation with trip setpoint devices and various control circuits. When an inverter is inoperable and its 118 VAC instrument bus is powered from the alternate power supply, there is increased potential for inadvertent actuation for ESFAS or RPS functions, especially if redundant channels are inoperable and in the tripped condition. This is because these 'de-energize to actuate functions' are relying upon interruptible AC electrical power sources (offsite and onsite). Therefore, only one inverter may be inoperable at one time and an inoperable inverter must be restored to OPERABLE within 24 hours. The 24 hour Completion Time is needed because it ensures that the 118 VAC instrument buses are powered from the uninterruptible inverter source. The 24 hour Completion Time is acceptable because Required Action A.1 ensures that an inoperable inverter does not result in a loss of any safety function.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.8 Inverters - Shutdown

BASES

BACKGROUND

A description of the inverters is provided in the Bases for LCO 3.8.7, "Inverters - Operating."

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Chapter 14 (Ref. 1), assume Engineered Safety Feature systems are OPERABLE. The DC to AC inverters are designed to provide the required capacity, capability, redundancy, and reliability to ensure the availability of necessary power to the Reactor Protection System and Engineered Safety Features Actuation System instrumentation and controls so that the fuel, Reactor Coolant System, and containment design limits are not exceeded.

The OPERABILITY of the inverters is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY.

The OPERABILITY of one inverter to each 118 VAC instrument bus during MODES 5 and 6 ensures that:

a. The unit can be maintained in the shutdown or refueling condition for extended periods,

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status, and

c. Adequate power is available to mitigate events postulated during shutdown, such as a fuel handling accident involving handling recently irradiated fuel. Due to radioactive decay, the AC and DC inverters are only required to mitigate fuel handling accidents involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 100 hours (Ref. 2)).

In general, when the unit is shut down, the Technical Specifications requirements ensure that the unit has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or all onsite power is not required. The rationale for this is based on the fact that many Design Basis Accidents

BASES

APPLICABILITY

The inverters required to be OPERABLE in MODES 5 and 6 and during movement of recently irradiated fuel assemblies provide assurance that:

a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel in the core,

b. Systems needed to mitigate a fuel handling accident involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 100 hours (Ref. 2)) are available,

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available, and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

Inverter requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.7.

ACTIONS

LCO 3.0.3 is not applicable while in MODE 5 or 6. However, since irradiated fuel assembly movement can occur in MODE 1, 2, 3, or 4, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operations. Entering LCO 3.0.3, while in MODE 1, 2, 3, or 4 would require the unit to be shutdown unnecessarily.

A.1, A.2.1, A.2.2, A.2.3, and A.2.4

If one or more 118 VAC instrument buses are required by LCO 3.8.10, "Distribution Systems - Shutdown," the remaining OPERABLE inverters may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS, recently irradiated fuel movement, and operations with a potential for positive reactivity additions. By the allowance of the option to declare required features inoperable with the associated inverter(s) inoperable, appropriate restrictions will be implemented in accordance with the affected required features LCOs' Required Actions. In many instances, this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS, movement of recently irradiated fuel assemblies, and operations involving positive reactivity additions) that could result in loss of required SDM (MODE 5) or boron concentration (MODE 6). Suspending

BASES

ACTIONS

LCO 3.0.3 is not applicable while in MODE 5 or 6. However, since irradiated fuel assembly movement can occur in MODE 1, 2, 3, or 4, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operations. Entering LCO 3.0.3, while in MODE 1, 2, 3, or 4 would require the unit to be shutdown unnecessarily.

A.1, A.2.1, A.2.2, A.2.3, A.2.4, and A.2.5

Although redundant required features may require redundant trains of electrical power distribution subsystems to be OPERABLE, one OPERABLE distribution subsystem train may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS and recently irradiated fuel movement. By allowing the option to declare required features associated with an inoperable distribution subsystem inoperable, appropriate restrictions are implemented in accordance with the affected distribution subsystem LCO's Required Actions. In many instances, this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS, movement of recently irradiated fuel assemblies, and operations involving positive reactivity additions that could result in loss of required SDM (MODE 5) or boron concentration (MODE 6). Suspending positive reactivity additions that could result in failure to meet the minimum SDM or boron concentration limit is required to assure continued safe operation. Introduction of coolant inventory must be from sources that have a boron concentration greater than what would be required in the RCS for minimum SDM or refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation. Introduction of temperature changes including temperature increases when operating with a positive MTC must also be evaluated to ensure they do not result in a loss of required SDM.

Suspension of these activities does not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required AC and DC electrical power distribution subsystems and to continue this action until restoration is accomplished in order to provide the necessary power to the unit safety systems.

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.3.1	Verify each required containment penetration is in the required status.	7 days
SR 3.9.3.2	- NOTE - Not required to be met for containment purge and exhaust valve(s) or pressure relief line isolation valve(s) in penetrations closed to comply with LCO 3.9.3.c.1. Verify each required containment purge and exhaust valve and pressure relief line isolation valve actuates to the isolation position on an actual or simulated actuation signal.	24 months

B 3.9 REFUELING OPERATIONS

B 3.9.3 Containment Penetrations

BASES

BACKGROUND

During movement of recently irradiated fuel assemblies within containment, a release of fission product radioactivity within containment will be restricted from escaping to the environment when the LCO requirements are met. In MODES 1, 2, 3, and 4, this is accomplished by maintaining containment OPERABLE as described in LCO 3.6.1, "Containment." In MODE 6, the potential for containment pressurization as a result of an accident is not likely; therefore, requirements to isolate the containment from the outside atmosphere can be less stringent. The LCO requirements are referred to as "containment closure" rather than "containment OPERABILITY." Containment closure means that all potential escape paths are closed or capable of being closed. Since there is no potential for containment pressurization, the Appendix J leakage criteria and tests are not required.

The containment serves to contain fission product radioactivity that may be released from the reactor core following an accident, such that offsite radiation exposures are maintained well within the requirements of 10 CFR 50.67, "Accident Source Term." Additionally, the containment provides radiation shielding from the fission products that may be present in the containment atmosphere following accident conditions.

The containment equipment hatch, which is part of the containment pressure boundary, provides a means for moving large equipment and components into and out of containment. During movement of recently irradiated fuel assemblies within containment, the opening must be closed using an equipment hatch closure plate that may include a personnel access door that is capable of being closed and the equipment hatch must be held in place by at least four bolts.

The containment air locks, which are also part of the containment pressure boundary, provide a means for personnel access during MODES 1, 2, 3, and 4 unit operation in accordance with LCO 3.6.2, "Containment Air Locks." Each air lock has a door at both ends. The doors are normally interlocked to prevent simultaneous opening when containment OPERABILITY is required. During periods of unit shutdown when containment closure is not required, the door interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods when frequent containment entry is necessary. During movement of recently irradiated fuel assemblies within containment, containment closure is required; therefore,

BASES

BACKGROUND (continued)

the door interlock mechanism may remain disabled, but one air lock door must always remain closed.

The requirements for containment penetration closure ensure that a release of fission product radioactivity within containment will be restricted to within regulatory limits.

A detailed description of the Containment Purge System (containment purge supply line and containment purge exhaust line) and the Containment Pressure Relief Line is provided in the Background of the Bases for Technical Specification 3.6.3, "Containment Isolation Valves."

Both the containment purge supply and exhaust isolation valves (FCV-1170, FCV-1171, FCV-1172, and FCV-1173) and the containment pressure relief line isolation valves (PCV-1190, PCV-1191 and PCV-1192) close when high radiation levels are detected by the Containment Air Particulate Monitor (R-41) or Containment Radioactive Gas Monitor (R-42). The Containment Phase A Isolation ESFAS signal (LCO 3.3.2, Function 3.a) and Containment Spray ESFAS signal (LCO 3.3.2, Function 2) also cause closure of the containment purge isolation valves and the containment pressure relief isolation valves.

The other containment penetrations that provide direct access from containment atmosphere to outside atmosphere must be isolated on at least one side. Isolation may be achieved by an OPERABLE automatic isolation valve, or by a manual isolation valve, blind flange, or equivalent. Equivalent isolation methods must be approved and may include use of a material that can provide a temporary, atmospheric pressure, ventilation barrier for the other containment penetrations during recently irradiated fuel movements (Ref. 1).

APPLICABLE SAFETY ANALYSES

At Indian Point 2, the radiological consequence analyses for the fuel handling accident demonstrate compliance with 10 CFR 50.67, "Accident Source Term." This analysis of a fuel handling accident is based on the assumption that decay time (i.e., fuel has decayed for greater than 100 hours) and water level are the primary success path for mitigating a fuel handling accident. This analysis assumed that activity from the damaged fuel assembly was released to the outside atmosphere through the containment purge system without taking any credit for either isolation or filtration of the release path (Ref. 2).

BASES

APPLICABLE SAFETY ANALYSES (continued)

Additionally, the analysis of a fuel handling accident (Ref. 2) demonstrated that 10 CFR 50.67 limits would be met even if the equipment hatch and personnel airlock remain open during the fuel handling accident inside containment. The analysis was performed to justify refueling operations with the containment personnel air locks and the equipment hatch open (Ref. 2).

However, the relaxations justified in Reference 2 do not apply when moving recently irradiated fuel (i.e., fuel assemblies that have been part of a critical reactor in the previous 100 hours). Therefore, during movement of recently irradiated fuel assemblies, LCO 3.9.3, "Containment Penetrations," establishes requirements for containment closure that minimize any release to the environment resulting from a fuel handling accident that occurs when the reactor has been subcritical for less than the 100 hours assumed in Reference 2.

Containment penetrations satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO limits the consequences of a fuel handling accident involving recently irradiated fuel in containment by limiting the potential escape paths for fission product radioactivity released within containment. The LCO requires any penetration providing direct access from the containment atmosphere to the outside atmosphere to be closed except for the OPERABLE containment purge and exhaust penetrations and pressure relief line penetration and the containment personnel air locks. For the OPERABLE containment purge and exhaust penetrations and pressure relief line penetration, this LCO ensures that these penetrations are isolable by the Containment Purge and Exhaust Isolation System. The OPERABILITY requirements for this LCO ensure that the automatic purge and exhaust valve closure times specified in the FSAR can be achieved and, therefore, meet the assumptions used in the safety analysis to ensure that releases through the valves are terminated, such that radiological doses are within the acceptance limit.

Technical Requirements Manual (TRM) 3.9.A specifies that movement of fuel in the reactor cannot be initiated until the reactor has been subcritical for ≥ 100 hours. Therefore, TRM 3.9.A prohibits movement of any fuel that can be classified as "recently irradiated."

BASES

LCO (continued)

The LCO is modified by a Note allowing penetration flow paths with direct access from the containment atmosphere to the outside atmosphere to be unisolated under administrative controls. Administrative controls ensure that 1) appropriate personnel are aware of the open status of the penetration flow path during CORE ALTERATIONS involving recently irradiated fuel or movement of recently irradiated fuel assemblies within containment, and 2) specified individuals are designated and readily available to isolate the flow path in the event of a fuel handling accident.

The containment personnel air lock doors may be open during movement of irradiated fuel in the containment and during CORE ALTERATIONS involving recently irradiated fuel provided that one door is capable of being closed in the event of a fuel handling accident. Should a fuel handling accident occur inside containment, one personnel air lock door will be closed following an evacuation of containment.

When moving irradiated fuel, the following guidelines should be included in the assessment of systems removed from service during movement of irradiated fuel:

- During fuel handling/core alterations, ventilation system and radiation monitor availability (as defined in NUMARC 91-06) should be assessed, with respect to filtration and monitoring of releases from the fuel. Following shutdown, radioactivity in the fuel decays away fairly rapidly. The basis of the Technical Specification OPERABILITY amendment is the reduction in doses due to such decay. The goal of maintaining ventilation system and radiation monitor availability is to reduce doses even further below that provided by the natural decay.

- A single normal or contingency method to promptly close primary or secondary containment penetrations should be developed. Such prompt methods need not completely block the penetration or be capable of resisting pressure.

The purpose of the "prompt methods" mentioned above are to enable ventilation systems to draw the release from a postulated fuel handling accident in the proper direction such that it can be treated and monitored.

APPLICABILITY

The containment penetration requirements are applicable during movement of recently irradiated fuel assemblies within containment because this is when there is a potential for the limiting fuel handling accident. In MODES 1, 2, 3, and 4, containment penetration requirements are addressed

BASES

ACTIONS (continued)

c. Each penetration providing direct access from the containment atmosphere to the outside atmosphere must be either closed by a manual or automatic isolation valve, blind flange, or equivalent, or verified to be capable of being closed by an OPERABLE Containment Purge System and Pressure Relief Line Isolation System.

With RHR loop requirements not met, the potential exists for the coolant to boil and release radioactive gas to the containment atmosphere. Performing the actions described above ensures that all containment penetrations are either closed or can be closed so that the dose limits are not exceeded.

The Completion Time of 4 hours allows fixing of most RHR problems and is reasonable, based on the low probability of the coolant boiling in that time.

SURVEILLANCE REQUIREMENTS

SR 3.9.4.1

This Surveillance demonstrates that the RHR loop is in operation and circulating reactor coolant. The flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability and to prevent thermal and boron stratification in the core. The Frequency of 12 hours is sufficient, considering the flow, temperature, pump control, and alarm indications available to the operator in the control room for monitoring the RHR System.

REFERENCES

None.

3.9 REFUELING OPERATIONS

3.9.5 Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level

LCO 3.9.5 Two RHR loops shall be OPERABLE, and one RHR loop shall be in operation.

- NOTES -

1. All RHR pumps may be removed from operation for ≤ 15 minutes when switching from one loop to another provided:

   a. The core outlet temperature is maintained > 10 degrees F subcooled,

   b. No operations are permitted that would cause a reduction of the Reactor Coolant System boron concentration, and

   c. No draining operations to further reduce RCS water volume are permitted.

2. One required RHR loop may be inoperable for up to 2 hours for surveillance testing, provided that the other RHR loop is OPERABLE and in operation.

APPLICABILITY: MODE 6 with the water level < 23 ft above the top of reactor vessel flange.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or both RHR loops inoperable.	A.1 Initiate action to restore required RHR loops to OPERABLE status. <u>OR</u> A.2 Initiate action to establish ≥ 23 ft of water above the top of reactor vessel flange.	Immediately Immediately

BASES

APPLICABLE SAFETY ANALYSES (continued)

is assumed to be released to the environment over a two hour period. These assumptions consistent with the guidance provided in DG-1081. The fuel assembly fission product inventory is based on the assumption that the subject fuel assembly has been operated at 1.7 times core average power (and thus has 1.7 times the average fuel assembly fission product inventory) (Ref. 2).

This analysis assumed that activity from the damaged fuel assembly was released to the outside atmosphere through the containment purge system without taking any credit for either isolation or filtration of the release path. This is conservative because the containment purge supply line, containment purge exhaust line and the containment pressure relief line are expected to be isolated by a Containment Air Particulate Monitor (R-42) or Radioactive Gas Monitor (R-41) even though this isolation is not required to meet 10 CFR 50.67 limits (Ref. 2).

Refueling cavity water level satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

A minimum refueling cavity water level of 23 ft above the reactor vessel flange is required to ensure that the radiological consequences of a postulated fuel handling accident inside containment are within acceptable limits.

APPLICABILITY

LCO 3.9.6 is applicable when moving irradiated fuel assemblies within containment. The LCO minimizes the possibility of a fuel handling accident in containment that is beyond the assumptions of the safety analysis. If irradiated fuel assemblies are not present in containment, there can be no significant radioactivity release as a result of a postulated fuel handling accident. Requirements for fuel handling accidents in the spent fuel pit are covered by LCO 3.7.11, "Spent Fuel Pit Water Level."

ACTIONS

A.1

With a water level of < 23 ft above the top of the reactor vessel flange, all operations involving or movement of irradiated fuel assemblies within the containment shall be suspended immediately to ensure that a fuel handling accident cannot occur.

The suspension of fuel movement shall not preclude completion of movement of a component to a safe position.

4.0 DESIGN FEATURES

4.1 Site Location

Indian Point 2 is located on the East bank of the Hudson River at Indian Point, Village of Buchanan, in upper Westchester County, New York. The site is approximately 24 miles north of the New York City boundary line. The nearest city is Peekskill which is 2.5 miles northeast of Indian Point.

The minimum distance from the reactor center line to the boundary of the site exclusion area and the outer boundary of the low population zone, as defined in 10 CFR 100.3, is 520 meters and 1100 meters, respectively. For the purpose of satisfying 10 CFR Part 20, the "Restricted Area" is the same as the "Exclusion Area" shown in UFSAR, Figure 2.2-2.

4.2 Reactor Core

4.2.1 Fuel Assemblies

The reactor shall contain 193 fuel assemblies. Each assembly shall consist of a matrix of Zircalloy-4 or ZIRLO fuel rods. Fuel shall have a U-235 enrichment of ≤ 5.0 weight percent. Limited substitutions of Zircalloy-4, ZIRLO or stainless steel filler rods for fuel rods, in accordance with approved applications of fuel rod configurations, may be used. Fuel assemblies shall be limited to those fuel designs that have been analyzed with applicable NRC staff approved codes and methods and shown by tests or analyses to comply with all fuel safety design bases. A limited number of lead test assemblies that have not completed representative testing may be placed in nonlimiting core regions.

4.2.2 Control Rod Assemblies

The reactor core shall contain 53 control rod assemblies. The control rod material shall be silver indium cadmium, clad with stainless steel, as approved by the NRC.

4.3 Fuel Storage

4.3.1 Criticality

4.3.1.1 The spent fuel storage racks are designed and shall be maintained with:

a. Fuel assemblies having a maximum U-235 enrichment of 5.0 weight percent,

4.0 DESIGN FEATURES

4.3 Fuel Storage (continued)

b. $k_{eff} < 1.0$ if fully flooded with unborated water, and

c. Each fuel assembly classified based on initial enrichment, burnup, cooling time and number of Integral Fuel Burnable Absorbers (IFBA) rods with individual fuel assembly storage location within the spent fuel storage rack restricted as required by Technical Specification 3.7.13.

4.3.1.2 The new fuel storage racks are designed and shall be maintained with:

a. Fuel assemblies having a maximum U-235 enrichment of 5.0 weight percent, and poisons, if necessary, to meet the limit for k_{eff},

b. $k_{eff} \leq 0.95$ if fully flooded with unborated water, and

c. A 20.5 inch center to center distance between fuel assemblies placed in the storage racks to meet the limit for k_{eff}.

4.3.2 Drainage

The spent fuel pit is designed and shall be maintained to prevent inadvertent draining of the pit below a nominal elevation of 88 feet, 6 inches.

4.3.3 Capacity

The spent fuel pit is designed and shall be maintained with a storage capacity limited to no more than 269 fuel assemblies in Region I and 1105 fuel assemblies in Region II.

5.0 ADMINISTRATIVE CONTROLS

5.2 Organization

5.2.1 Onsite and Offsite Organizations

Onsite and offsite organizations shall be established for unit operation and corporate management, respectively. The onsite and offsite organizations shall include the positions for activities affecting safety of the nuclear power plant.

a. Lines of authority, responsibility, and communication shall be defined and established throughout highest management levels, intermediate levels, and all operating organization positions. These relationships shall be documented and updated, as appropriate, in organization charts, functional descriptions of departmental responsibilities and relationships, and job descriptions for key personnel positions, or in equivalent forms of documentation. These requirements including the plant-specific titles of those personnel fulfilling the responsibilities of the positions delineated in these Technical Specifications shall be documented in the UFSAR,

b. The plant manager shall be responsible for overall safe operation of the plant and shall have control over those onsite activities necessary for safe operation and maintenance of the plant,

c. The corporate officer with direct responsibility for the plant shall have corporate responsibility for overall plant nuclear safety and shall take any measures needed to ensure acceptable performance of the staff in operating, maintaining, and providing technical support to the plant to ensure nuclear safety, and

d. The individuals who train the operating staff, carry out health physics, or perform quality assurance functions may report to the appropriate onsite manager; however, these individuals shall have sufficient organizational freedom to ensure their independence from operating pressures.

5.2.2 Unit Staff

The unit staff organization shall include the following:

a. A non-licensed operator shall be assigned to each reactor containing fuel and an additional non-licensed operator shall be assigned for each control room from which a reactor is operating in MODES 1, 2, 3, or 4.

5.2 Organization

5.2.2 Unit Staff (continued)

b. Shift crew composition may be less than the minimum requirement of 10 CFR 50.54(m)(2)(i) and 5.2.2.a and 5.2.2.f for a period of time not to exceed 2 hours in order to accommodate unexpected absence of on-duty shift crew members provided immediate action is taken to restore the shift crew composition to within the minimum requirements.

c. A radiation protection technician shall be on site when fuel is in the reactor. The position may be vacant for not more than 2 hours, in order to provide for unexpected absence, provided immediate action is taken to fill the required position.

d. Administrative procedures shall be developed and implemented to limit the working hours of personnel who perform safety related functions (e.g., licensed Senior Reactor Operators (SROs), licensed Reactor Operators (ROs), health physicists, auxiliary operators, and key maintenance personnel).

   The controls shall include guidelines on working hours that ensure adequate shift coverage shall be maintained without routine heavy use of overtime.

   Any deviation from the above guidelines shall be authorized in advance by the plant manager or the plant manager's designee, in accordance with approved administrative procedures, and with documentation of the basis for granting the deviation. Routine deviation from the working hour guidelines shall not be authorized.

   Controls shall be included in the procedures to require a periodic independent review be conducted to ensure that excessive hours have not been assigned.

e. The operations manager or assistant operations manager shall hold an SRO license.

f. A Watch Engineer shall provide advisory technical support to the unit operations shift crew in the areas of thermal hydraulics, reactor engineering, and plant analysis with regard to the safe operation of the unit. This individual shall meet the qualifications specified by the Commission Policy Statement on Engineering Expertise on Shift. The Watch Engineer position must be manned only when in MODES 1, 2, 3, and 4 and during CORE ALTERATIONS.

5.0 ADMINISTRATIVE CONTROLS

5.4 Procedures

5.4.1 Written procedures shall be established, implemented, and maintained covering the following activities:

a. The applicable requirements and recommendations of Sections 5.2 and 5.3 of ANSI N18.7-1976 and Appendix A of Regulatory Guide 1.33, Revision 2 except as provided in the quality assurance program described or referenced in the Updated FSAR;

b. The emergency operating procedures required to implement the requirements of NUREG-0737 and NUREG-0737, Supplement 1, as stated in Generic Letter 82-33;

c. Quality assurance for effluent and environmental monitoring;

d. Fire Protection Program implementation;

e. All programs specified in Technical Specification 5.5; and

f. Personnel radiation protection consistent with the requirements of 10 CFR 20.

5.5 Programs and Manuals

5.5.2 Primary Coolant Sources Outside Containment

This program provides controls to minimize leakage from those portions of systems outside containment that could contain highly radioactive fluids during a serious transient or accident to levels as low as practicable. The systems include:

a. Residual Heat Removal System (RHR);

b. Chemical and Volume Control System (CVCS);

c. Safety Injection System (SIS);

d. Primary Sampling System (PSS) / Post Accident Sampling System (PASS) (until such time that a modification eliminates the PASS as a potential leakage path);

e. Post Accident Containment Air Sampling System (PACAS) (until such time that a modification eliminates the PASS as a potential leakage path);

f. Post Accident Containment Vent System (PACVS);

g. Gaseous Waste Disposal System (WDS); and

h. Secondary Boiler Blowdown Purification System (SBBPS) High Pressure Test.

The program shall include the following:

a. Preventive maintenance and periodic visual inspection requirements and

b. Integrated leak test requirements for each system at least once per 24 months.

The provisions of SR 3.0.2 are applicable.

5.5.3 Radioactive Effluent Controls Program

This program conforms to 10 CFR 50.36a for the control of radioactive effluents and for maintaining the doses to members of the public from radioactive effluents as low as reasonably achievable. The program shall be contained in the ODCM, shall be implemented by procedures, and shall include remedial actions to be taken whenever the program limits are exceeded. The program shall include the following elements:

5.5 Programs and Manuals

5.5.3 Radioactive Effluent Controls Program (continued)

a. Limitations on the functional capability of radioactive liquid and gaseous monitoring instrumentation including surveillance tests and setpoint determination in accordance with the methodology in the ODCM,

b. Limitations on the concentrations of radioactive material released in liquid effluents to unrestricted areas, conforming to concentrations specified in 10 CFR Part 20, Appendix B, Table II, Column 2, for radionuclides other than dissolved or entrained noble gases. For dissolved or entrained noble gases, the concentration shall be limited to 2×10^{-4} microcuries/ml.

c. Monitoring, sampling, and analysis of radioactive liquid and gaseous effluents in accordance with 10 CFR 20.1302 and with the methodology and parameters in the ODCM,

d. Limitations on the annual and quarterly doses or dose commitment to a member of the public from radioactive materials in liquid effluents released from each unit to unrestricted areas, such that:

1. The dose or dose commitment during any calendar quarter is less than or equal to 1.5 mrem to the total body and less than or equal to 5 mrem to any organ, and

2. The dose or dose commitment during any calendar year is less than or equal to 3 mrem to the total body and to less than or equal to 10 mrem to any organ.

e. Determination of cumulative dose contributions from radioactive effluents for the current calendar quarter and current calendar year in accordance with the methodology and parameters in the ODCM at least every 31 days. Determination of projected dose contributions from radioactive effluents in accordance with the methodology in the ODCM at least every 31 days,

f. Limitations on the functional capability and use of the liquid and gaseous effluent treatment systems to ensure that appropriate portions of these systems are used to reduce releases of radioactivity when the projected doses in a period of 31 days would exceed the following:

1. For liquid effluent treatment systems, projected dose due to liquid effluent releases from each reactor unit would exceed 0.06 mrem to the total body or 0.2 mrem to any organ, and

5.5 Programs and Manuals

5.5.6 Inservice Testing Program (continued)

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 Steam Generator (SG) Tube Surveillance Program

This program assures the continued integrity of the steam generator tubes that are a part of the primary coolant pressure boundary. Steam generator tubes shall be determined OPERABLE by the following inspection program and corrective measures:

a. Definitions

1. Imperfection is a deviation from the dimension, finish, or contour required by drawing or specification.

2. Deformation is a deviation from the initial circular cross-section of the tubing. Deformation includes the deviation from the initial circular cross-section known as denting.

3. Degradation means service-induced cracking, wastage, pitting, wear or corrosion (i.e., service-induced imperfections).

4. Degraded Tube is a tube that contains imperfections caused by degradation large enough to be reliably detected by eddy current inspection. This is considered to be 20% degradation.

5. % Degradation is an estimated % of the tube wall thickness affected or removed by degradation.

6. Defect is a degradation of such severity that it exceeds the plugging limit. A tube containing a defect is defective.

7. Plugging Limit is the degradation depth at or beyond which the tube must be plugged or repaired.

8. Hot-Leg Tube Examination is an examination of the hot-leg side tube length. This shall include the length from the point of entry at the hot-leg tube sheet around the U-bend to the top support of the cold leg.

5.5 Programs and Manuals

5.5.8 Secondary Water Chemistry Program

This program provides controls for monitoring secondary water chemistry to inhibit SG tube degradation. The program shall include:

a. Identification of a sampling schedule for the critical variables and control points for these variables,

b. Identification of the procedures used to measure the values of the critical variables,

c. Identification of process sampling points.

d. Procedures for the recording and management of data,

e. Procedures defining corrective actions for all off control point chemistry conditions, and

f. A procedure identifying the authority responsible for the interpretation of the data and the sequence and timing of administrative events, which is required to initiate corrective action.

5.5.9 Ventilation Filter Testing Program (VFTP)

A program shall be established to implement the following required testing of the Control Room Ventilation System (CRVS) in accordance with Regulatory Guide 1.52, Revision 2, March 1978, and ANSI N510-1975. Tests described in Technical Specifications 5.5.9.a, 5.5.9.b, 5.5.9.c and 5.5.9.d shall be performed:

1) Within 31 days after 720 hours of charcoal adsorber operation since the last test (requires performance of 5.5.9.c only);

2) After 24 months of standby service;

3) After each complete or partial replacement of the HEPA filter train or charcoal adsorber filter;

4) After any structural maintenance on the system housing that could alter system integrity; and

5) After painting, fire, or chemical release in any ventilation zone communicating with the system while it is in operation.

5.5 Programs and Manuals

5.5.9 Ventilation Filter Testing Program (VFTP) (continued)

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Ventilation Filter Testing Program.

The Required testing shall:

a. Demonstrate 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 Position C.5.c of Regulatory Guide 1.52, Revision 2, March 1978, and ANSI N510-1975, while operating the system at ambient conditions and at a flow rate of 2000 cfm ±10%.

b. Demonstrate that an inplace test of the charcoal adsorber shows a penetration and system bypass < 0.05% when tested in accordance with Regulatory Position C.5.d of Regulatory Guide 1.52, Revision 2, March 1978, and ANSI N510-1975, while operating the system at ambient conditions and at a flow rate of 2000 cfm ±10%.

c. Demonstrate that a laboratory test of a sample of the charcoal adsorber, when obtained as described in Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, shows the methyl iodide penetration less than 5.0% when tested in accordance with ASTM D3803-1989 at a temperature of 30°C (86°F) and a relative humidity of 95%, and a face velocity of 0.203 m/sec (40 ft/min).

d. Demonstrate that the pressure drop across the combined HEPA filters, the prefilters, and the charcoal adsorbers is less than 6 inches water gauge when tested in accordance with Regulatory Guide 1.52, Revision 2, and N510-1975 at the system flowrate of 2000 cfm (± 10%).

5.5.10 Explosive Gas and Storage Tank Radioactivity Monitoring Program

This program provides controls for potentially explosive gas mixtures contained in the Waste Gas Holdup System, the quantity of radioactivity contained in gas storage tanks, and the quantity of radioactivity contained in unprotected outdoor liquid storage tanks. The gaseous radioactivity quantities shall be determined following the methodology in Branch Technical Position (BTP) ETSB 11-5, "Postulated Radioactive Release due to Waste Gas System Leak or Failure." The liquid radwaste quantities shall be determined in accordance with Standard Review Plan, Section 15.7.3, "Postulated Radioactive Release due to Tank Failures."

5.5 Programs and Manuals

5.5.10 Explosive Gas and Storage Tank Radioactivity Monitoring Program (continued)

The program shall include:

a. The limits for concentrations of hydrogen and oxygen in the Waste Gas Holdup System and a surveillance program to ensure the limits are maintained. Such limits shall be appropriate to the system's design criteria (i.e., whether or not the system is designed to withstand a hydrogen explosion),

b. A surveillance program to ensure that the quantity of radioactivity contained in each gas storage tank is less than the amount that would result in a whole body exposure of ≥ 0.5 rem to any individual in an unrestricted area, in the event of an uncontrolled release of the tanks' contents, and

c. A surveillance program to ensure that the quantity of radioactivity contained in all outdoor liquid radwaste tanks that are not surrounded by liners, dikes, or walls, capable of holding the tanks' contents and that do not have tank overflows and surrounding area drains connected to the Liquid Radwaste Treatment System is less than the amount that would result in concentrations less than the limits of 10 CFR 20, Appendix B, Table 2, Column 2, at the nearest potable water supply and the nearest surface water supply in an unrestricted area, in the event of an uncontrolled release of the tanks' contents.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Explosive Gas and Storage Tank Radioactivity Monitoring Program surveillance frequencies.

5.5.11 Diesel Fuel Oil Testing Program

A diesel fuel oil testing program to implement required testing of both new fuel oil and stored fuel oil shall be established for the onsite DG fuel oil storage tanks and the DG reserve fuel oil storage tanks. The program shall include sampling and testing requirements, and acceptance criteria, all in accordance with applicable ASTM Standards. The purpose of the program is to establish the following:

a. Verification of the acceptability of new fuel oil for use prior to addition to the DG fuel oil onsite storage tanks by determining that the fuel oil has:

1. Relative density within the limits of 0.83 to 0.89;

2. Kinematic viscosity within the limits of 1.8 to 5.8; and

5.5 Programs and Manuals

5.5.11 Diesel Fuel Oil Testing Program (continued)

3. A clear and bright appearance with proper color.

b.1 Verification of the acceptability of the fuel oil in the onsite storage tanks and the reserve storage tanks every 92 days by verifying that the properties of the fuel oil in the tanks, other than those addressed in item a, are within limits for ASTM 2D fuel oil. The sampling technique for the reserve storage tanks may deviate from ASTM D270-1975 in that only a bottom sample is required; or

b.2 Verification of the acceptability of each new fuel addition made subsequent to the last verification made in accordance with item b.1 by verifying, within 31 days following the addition, that the properties of the new fuel oil, other than those properties addressed in item a, are within limits for ASTM 2D fuel oil.

c. Verification every 92 days that total particulate concentration of the fuel oil in the onsite and reserve storage tanks is less than or equal to 10 mg/l when tested in accordance with ASTM D-2276, Method A-2 or A-3. The sampling technique for the reserve storage tanks may deviate from ASTM D270-1975 in that only a bottom sample is required.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Diesel Fuel Oil Testing Program testing frequencies.

5.5.12 Technical Specifications (TS) Bases Control Program

This program provides a means for processing changes to the Bases of these Technical Specifications.

a. Changes to the Bases of the TS shall be made under appropriate administrative controls and reviews.

b. Licensees may make changes to Bases without prior NRC approval provided the changes do not require either of the following:

1. A change in the TS incorporated in the license or

2. A change to the updated UFSAR or Bases that requires NRC approval pursuant to 10 CFR 50.59.

c. The Bases Control Program shall contain provisions to ensure that the Bases are maintained consistent with the UFSAR.

5.5 Programs and Manuals

5.5.13 Safety Function Determination Program (SFDP) (continued)

The SFDP identifies where a loss of safety function exists. If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered. When a loss of safety function is caused by the inoperability of a single Technical Specification support system, the appropriate Conditions and Required Actions to enter are those of the support system.

5.5.14 Containment Leakage Rate Testing Program

a. A program shall establish the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," dated September, 1995, as modified by the following exception:

   The Type A testing frequency specified in NEI 94-01, paragraph 9.2.3, as at-least-once-per-10 years based on acceptable performance history is changed to allow a Type A testing frequency of at-least-once-per-15 years based on acceptable performance history. This is a one-time-only exception that applies only for the interval following the Type A test performed in June 1991.

b. The calculated peak containment internal pressure for the design basis loss of coolant accident, P_a, is assumed to be the containment design pressure of 47 psig.

c. The maximum allowable containment leakage rate, L_a, at P_a, and 271°F shall be 0.1% of containment steam air weight per day.

d. Leakage rate acceptance criteria:

   1. Containment leakage rate acceptance criterion is 1.0 L_a. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are < 0.60 L_a for the Type B and C tests and ≤ 0.75 L_a for Type A tests.

   2. Air lock testing acceptance criteria shall be established to ensure that limits for Type B and C testing in Technical Specification 5.5.14.d.1 are met.

5.5 Programs and Manuals

5.5.14 Containment Leakage Rate Testing Program (continued)

3. Isolation Valve Seal Water System leakage rate acceptance criteria is $\leq$ 14,700 cc/hour.

e. Acceptance criterion for leakage into containment from isolation valves sealed with the service water system is $\leq$ 0.36 gpm per fan cooler unit when pressurized at $\geq$ 1.1 P_a. This limit protects the internal recirculation pumps from flooding during the 12-month period of post accident recirculation.

f. The provisions of SR 3.0.3 are applicable to the Containment Leakage Rate Testing Program.

g. Nothing in these Technical Specifications shall be construed to modify the testing Frequencies required by 10 CFR 50, Appendix J.

5.5.15 <u>Battery Monitoring and Maintenance Program</u>

This program provides for battery restoration and maintenance, based on the recommendations of IEEE Standard 450-1995, "IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications," or of the battery manufacturer including the following:

a. Actions to restore battery cells with float voltage < 2.13 V, and

b. Actions to equalize the test battery cells that had been discovered with electrolyte level below the minimum established design limit.

5.6 Reporting Requirements

5.6.5 CORE OPERATING LIMITS REPORT (COLR) (continued)

8. Technical Specification 3.2.3, Axial Flux Difference (AFD);

9. Technical Specification 3.3.1, Reactor Protection System Instrumentation;

10. Technical Specification 3.4.1, RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits; and

11. Technical Specification 3.9.1, Boron Concentration.

b. The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

1. WCAP-9272-P-A, "Westinghouse Reload Safety Evaluation Methodology," July 1985;

2. WCAP-8385, "Power Distribution Control and Load Following Procedures - Topical Report", September 1974;

3. T.M. Anderson to K. Kniel (NRC) January 31, 1980 - Attachment: Operation and Safety Analysis Aspects of an Improved Load Follow Package;

4. NUREG-0800, Standard Review Plan, US Nuclear Regulatory Commission, Section 4.3, Nuclear Design, July 1981, including Branch Technical Position CPB 4.3-1,Westinghouse Constant Axial Offset Control (CAOC), Rev. 2, July 1981;

5. WCAP-10266-P-A Rev. 2, "The 1981 Version of Westinghouse Evaluation Model Using Bash Code", March 1987; and

6. WCAP-12945-P, Westinghouse "Code Qualification Document for Best Estimate LOCA Analyses", July, 1996.

7. Caldon, Inc. Engineering Report-80P, "Improving Thermal Power Accuracy and Plant Safety While Increasing Operating Power Level Using the LEFM System," Revision 0, March 1997, and Caldon, Inc. Engineering Report-160P, "Supplement to Topical Report ER-80P: Basis for a Power Uprate With the LEFM System," Revision 0, May 2000.