Indian Point 3

Improved

Technical Specifications

Conversion Submittal

Volume 5

New York Power Authority

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.1:
"Reactor Protection System (RPS) Instrumentation"

PART 1:

Indian Point 3
Improved Technical Specifications and Bases

3.3 INSTRUMENTATION

3.3.1 Reactor Protection System (RPS) Instrumentation

LCO 3.3.1 The RPS instrumentation for each Function in Table 3.3.1-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.1-1.

ACTIONS

----------NOTES----------

1. Separate Condition entry is allowed for each Function.
2. When a channel or train is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 8 hours provided the associated Function maintains RPS trip capability.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more Functions with one or more required channels or trains inoperable.	A.1	Enter the Condition referenced in Table 3.3.1-1 for the channel(s) or train (s).	Immediately
B. One Manual Reactor Trip channel inoperable.	B.1	Restore channel to OPERABLE status.	48 hours
	OR		
	B.2	Be in MODE 3.	54 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One channel or train inoperable.	C.1 Restore channel or train to OPERABLE status.	48 hours
	OR	
	C.2.1 Initiate action to fully insert all rods.	48 hours
	AND	
	C.2.2 Place the Rod Control System in a condition incapable of rod withdrawal.	49 hours
D. One Power Range Neutron Flux – High channel inoperable.	----------NOTE---------- The inoperable channel may be bypassed for up to 8 hours for surveillance testing and setpoint adjustment of other channels. ----------	
	D.1.1 Place channel in trip.	6 hours
	AND	
	D.1.2 Reduce THERMAL POWER to ≤ 75% RTP.	24 hours
	OR	
	D.2.1 Place channel in trip.	6 hours
	AND	
		(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. (continued)	----------NOTE---------- Only required to be performed when the Power Range Neutron Flux input to QPTR is inoperable. ----------	
	D.2.2 Perform SR 3.2.4.2.	Once per 24 hours
	OR	
	D.3 Be in MODE 3.	12 hours
E. One channel inoperable.	----------NOTE---------- The inoperable channel may be bypassed for up to 8 hours for surveillance testing of other channels. ----------	
	E.1 Place channel in trip.	6 hours
	OR	
	E.2 Be in MODE 3.	12 hours
F. Required Intermediate Range Neutron Flux channel inoperable.	F.1 Suspend operations involving positive reactivity additions.	Immediately
	AND	
	F.2 Reduce THERMAL POWER to < P-6.	2 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
G. Required Source Range Neutron Flux channel inoperable.	G.1 Open Reactor Trip Breakers (RTBs).	Immediately
H. One channel inoperable.	----------NOTE---------- The inoperable channel may be bypassed for up to 8 hours for surveillance testing of other channels. ----------	
	H.1 Place channel in trip.	6 hours
	OR	
	H.2 Reduce THERMAL POWER to < P-7.	12 hours
I. One Reactor Coolant Pump Breaker Position channel inoperable.	----------NOTE---------- The inoperable channel may be bypassed for up to 8 hours for surveillance testing of other channels. ----------	
	I.1 Restore channel to OPERABLE status.	6 hours
	OR	
	I.2 Reduce THERMAL POWER to < P-8.	10 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
J. One Turbine Trip channel inoperable.	----------NOTE---------- The inoperable channel may be bypassed for up to 8 hours for surveillance testing of other channels. ----------	
	J.1 Place channel in trip.	6 hours
	OR	
	J.2 Reduce THERMAL POWER to < P-7.	12 hours
K. One train inoperable.	----------NOTE---------- One train may be bypassed for up to 8 hours for surveillance testing provided the other train is OPERABLE. ----------	
	K.1 Restore train to OPERABLE status.	6 hours
	OR	
	K.2 Be in MODE 3.	12 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
L. One RTB train inoperable.	----------NOTES---------- 1. One train may be bypassed for up to 2 hours for testing, provided the other train is OPERABLE. 2. One RTB may be bypassed for up to 2 hours for maintenance on undervoltage or shunt trip mechanisms, provided the other train is OPERABLE. ----------	
	L.1 Restore train to OPERABLE status.	1 hour
	OR	
	L.2 Be in MODE 3.	7 hours
M. One or more channels inoperable.	M.1 Verify interlock is in required state for existing unit conditions.	1 hour
	OR	
	M.2 Be in MODE 3.	7 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
N. One or more channels inoperable.	N.1	Verify interlock is in required state for existing unit conditions.	1 hour
	OR		
	N.2	Be in MODE 2.	7 hours
O. One trip mechanism inoperable for one RTB.	O.1	Restore inoperable trip mechanism to OPERABLE status.	48 hours
	OR		
	O.2.	Be in MODE 3.	54 hours

SURVEILLANCE REQUIREMENTS

----------NOTE----------
Refer to Table 3.3.1-1 to determine which SRs apply for each RPS Function.

SURVEILLANCE		FREQUENCY
SR 3.3.1.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.1.2	----------NOTES---------- 1. Adjust NIS channel if absolute difference is > 2%. 2. Not required to be performed until 24 hours after THERMAL POWER is ≥ 15% RTP. --- Compare results of calorimetric heat balance calculation to Nuclear Instrumentation System (NIS) channel output.	24 hours
SR 3.3.1.3	----------NOTES---------- 1. Adjust NIS channel if absolute difference is ≥ 3%. 2. Only required to be performed when THERMAL POWER is > 90% RTP. --- Compare results of the incore detector measurements to NIS AFD.	31 effective full power days (EFPD)

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.4	----------NOTE---------- This Surveillance must be performed on the reactor trip bypass breaker prior to placing the bypass breaker in service. ---------- Perform TADOT.	31 days on a STAGGERED TEST BASIS
SR 3.3.1.5	Perform ACTUATION LOGIC TEST.	31 days on a STAGGERED TEST BASIS
SR 3.3.1.6	----------NOTE---------- Only required to be performed when THERMAL POWER is > 90% RTP. ---------- Calibrate excore channels to agree with incore detector measurements.	31 EFPD
SR 3.3.1.7	----------NOTE---------- Not required to be performed for source range instrumentation prior to entering MODE 3 from MODE 2 until 8 hours after entry into MODE 3. ---------- Perform COT.	92 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.8	----------NOTE---------- This Surveillance shall include verification that interlocks P-6 and P-10 are in their required state for existing unit conditions. ---------- Perform COT.	------NOTE------ Only required when not performed within previous 92 days ---------- Prior to reactor startup AND Sixteen hours after reducing power below P-10 for power and intermediate instrumentation AND Eight hours after reducing power below P-6 for source range instrumentation AND Every 92 days thereafter

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.9	----------NOTE---------- Verification of setpoint is not required. ---------- Perform TADOT.	92 days
SR 3.3.1.10	----------NOTE---------- This Surveillance shall include verification that the time constants are adjusted to the prescribed values. ---------- Perform CHANNEL CALIBRATION.	24 months AND 18 months for Function 11
SR 3.3.1.11	----------NOTE---------- Neutron detectors are excluded from CHANNEL CALIBRATION. ---------- Perform CHANNEL CALIBRATION.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.12	----------NOTE---------- This Surveillance shall include verification that the electronic dynamic compensation time constants are set at the required values. ---------- Perform CHANNEL CALIBRATION.	24 months
SR 3.3.1.13	Perform COT.	24 months
SR 3.3.1.14	----------NOTE---------- Verification of setpoint is not required. ---------- Perform TADOT.	24 months
SR 3.3.1.15	----------NOTE---------- Verification of setpoint is not required. ---------- Perform TADOT.	24 months

Table 3.3.1-1 (page 1 of 8)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Manual Reactor Trip	1,2	2	B	SR 3.3.1.14	NA
	3[a], 4[a], 5[a]	2	C	SR 3.3.1.14	NA
2. Power Range Neutron Flux					
a. High	1,2	4	D	SR 3.3.1.1 SR 3.3.1.2 SR 3.3.1.7 SR 3.3.1.11	≤ 109% RTP
b. Low	1[b],2	4	E	SR 3.3.1.1 SR 3.3.1.8 SR 3.3.1.11	≤ 25% RTP
3. Intermediate Range Neutron Flux	1[b], 2[c]	1	F	SR 3.3.1.1 SR 3.3.1.8 SR 3.3.1.11	NA

(continued)

(a) With Rod Control System capable of rod withdrawal and one or more rods not fully inserted.

(b) Below the P-10 (Power Range Neutron Flux) interlocks.

(c) Above the P-6 (Intermediate Range Neutron Flux) interlocks.

Table 3.3.1-1 (page 2 of 8)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
4. Source Range Neutron Flux	2[d]	1	G	SR 3.3.1.1 SR 3.3.1.8 SR 3.3.1.11	NA
	3[a], 4[a], 5[a]	1	G	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.11	NA
5. Overtemperature ΔT	1,2	4	E	SR 3.3.1.1 SR 3.3.1.3 SR 3.3.1.6 SR 3.3.1.7 SR 3.3.1.12	Refer to Note 1
6. Overpower ΔT	1,2	4	E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.12	Refer to Note 2

(continued)

(a) With Rod Control System capable of rod withdrawal and one or more rods not fully inserted.

(d) Below the P-6 (Intermediate Range Neutron Flux) interlocks.

Table 3.3.1-1 (page 3 of 8)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
7. Pressurizer Pressure					
a. Low	1(e)	4	H	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≥ 1749 psig
b. High	1,2	3	E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≤ 2408.24 psig
8. Pressurizer Water Level – High	1(e)	3	H	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≤ 97.47%
9. Reactor Coolant Flow – Low	1(e)	3 per loop(j)	H	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≥ 89%

(continued)

(e) Above the P-7 (Low Power Reactor Trips Block) interlock.

(j) Separate condition entry is allowed for each loop.

Table 3.3.1-1 (page 4 of 8)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
10. Reactor Coolant Pump (RCP) Breaker Position					
a. Single Loop	1[f]	1 per RCP	I	SR 3.3.1.14	NA
b. Two Loops	1[g]	1 per RCP	H	SR 3.3.1.14	NA
11. Undervoltage RCPs (6.9 kV bus)	1[e]	1 per bus	H	SR 3.3.1.9 SR 3.3.1.10	≥ 68.37% V
12. Underfrequency RCPs (6.9 kV bus)	1[e]	1 per bus	H	SR 3.3.1.9 SR 3.3.1.10	≥ 57.22 Hz
13. Steam Generator (SG) Water Level – Low Low	1,2	3 per SG[k]	E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≥ 3.54%
14. SG Water Level – Low	1,2	2 per SG[k]	E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	NA
Coincident with Steam Flow/Feedwater Flow Mismatch	1,2	2 per SG[k]	E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	NA

(continued)

(e) Above the P-7 (Low Power Reactor Trips Block) interlock.

(f) Above the P-8 (Power Range Neutron Flux) interlock.

(g) Above the P-7 (Low Power Reactor Trips Block) interlock and below the P-8 (Power Range Neutron Flux) interlock.

(k) Separate condition entry is allowed for each SG.

Table 3.3.1-1 (page 5 of 8)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
15. Turbine Trip-Auto-Stop Oil Pressure	1(h)	3	J	SR 3.3.1.10 SR 3.3.1.15	NA
16. Safety Injection (SI) Input from Engineered Safety Feature Actuation System (ESFAS)	1,2	2 trains	K	SR 3.3.1.14	NA
17. Reactor Trip System Interlocks					
a. Intermediate Range Neutron Flux, P-6	2(d)	2 trains	M	SR 3.3.1.11 SR 3.3.1.13	NA
b. Low Power Reactor Trips Block, P-7	1	2 trains	N	SR 3.3.1.11 SR 3.3.1.13	NA
c. Power Range Neutron Flux, P-8	1	4	N	SR 3.3.1.11 SR 3.3.1.13	≤ 50.0% RTP
d. Power Range Neutron Flux, P-10	1,2	4	M	SR 3.3.1.11 SR 3.3.1.13	< 10% RTP
e. Turbine First Stage Pressure, P-7 Input	1	2	N	SR 3.3.1.1 SR 3.3.1.10 SR 3.3.1.13	< 10% turbine power

(continued)

(d) Below the P-6 (Intermediate Range Neutron Flux) interlocks.

(h) Above the P-7 (Low Power Reactor Trips Block) interlock except during turbine overspeed trip testing.

Table 3.3.1-1 (page 6 of 8)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
18. Reactor Trip Breakers(RTBs)[i]	1,2	2 trains	L	SR 3.3.1.4	NA
	3[a], 4[a], 5[a]	2 trains	C	SR 3.3.1.4	NA
19. Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms	1,2	1 each per RTB	O	SR 3.3.1.4	NA
	3[a], 4[a], 5[a]	1 each per RTB	C	SR 3.3.1.4	NA
20. Automatic Trip Logic	1,2	2 trains	K	SR 3.3.1.5	NA
	3[a], 4[a], 5[a]	2 trains	C	SR 3.3.1.5	NA

(a) With Rod Control System capable of rod withdrawal and one or more rods not fully inserted.

(i) Including any reactor trip bypass breakers that are racked in and closed for bypassing an RTB.

Table 3.3.1-1 (page 7 of 8)
Reactor Protection System Instrumentation

Note 1: Overtemperature ΔT

The Overtemperature ΔT Function Allowable Value shall not exceed the following:

$$\Delta T \leq \Delta T_o [K_1 - K_2 [(1 + \tau_1 s)/(1 + \tau_2 s)] (T_{avg} - T') + K_3 (P - P') - f(\Delta I)]$$

Where: $K_1 \leq 1.285$ $K_2 = 0.0273$ $K_3 = 0.0013$

$\tau_1 \geq 25$ seconds $\tau_2 \leq 3$ seconds

ΔT_o = Measured full power ΔT for the channel being calibrated, °F.

T_{avg} = Average Temperature for the channel being calibrated, °F (input from instrument racks)

s = Laplace transform operator, $seconds^{-1}$

T' = Measured full power T_{avg} for the channel being calibrated, °F

P = Pressurizer pressure, psig (input from instrument racks)

P' = 2235 psig (i.e., nominal pressurizer pressure at rated power)

K_1 is a constant which defines the overtemperature ΔT trip margin during steady state operation if the temperature, pressure, and $f(\Delta I)$ terms are zero.

K_2 is a constant which defines the dependence of the overtemperature ΔT setpoint to T_{avg}.

K_3 is a constant which defines the dependence of the overtemperature ΔT setpoint to pressurizer pressure.

τ dynamic compensation time constants

ΔI = $q_t - q_b$, where q_t and q_b are the percent power in the top and bottom halves of the core respectively, and $q_t + q_b$ is total core power in percent of RTP.

$f(\Delta I)$ = 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, where q_t and q_b are defined above such that:

(a) for $q_t - q_b$ between -15.75% and +6.9%, $f(\Delta I)=0$.

(b) for each percent that the magnitude of $q_t - q_b$ exceeds +6.9%, the ΔT trip setpoint shall be automatically reduced by an equivalent of 3.333% of RTP.

(c) or each percent that the magnitude of $q_t - q_b$ is more negative than -15.75%, the ΔT trip setpoint shall be automatically reduced by an equivalent of 4.000% of RTP.

Table 3.3.1-1 (page 8 of 8)
Reactor Protection System Instrumentation

Note 2: Overpower ΔT

The Overpower ΔT Function Allowable Value shall not exceed the following:

$$\Delta T \leq \Delta T_o (K_4 - K_5 (dTavg/dt) - K_6(T_{avg} - T'))$$

Where:

$K_4 \leq 1.154$

$K_5 = 0$ for decreasing average temperature; and
≥ 0.175 sec/°F for increasing average temperature

$K_6 = 0$ for $T \leq T'$; and
≥ 0.00134 for $T > T'$

$\Delta T_o \leq$ measured full power ΔT for the channel being calibrated, °F

T_{avg} = measured average temperature for the channel being calibrated, °F (input from instrument racks)

T' = measured full power T_{avg} for the channel being calibrated, °F (can be set no higher than 570.3 °F)

s = Laplace transform operator, seconds

K_4 is a constant which defines the overpower ΔT trip margin during steady state operation if the temperature term is zero.

K_5 is a constant determined by dynamic considerations to compensate for piping delays from the core to the loop temperature detectors; it represents the combination of the equipment static gain setting and the time constant setting.

K_6 is a constant which defines the dependence of the overpower ΔT setpoint to T_{avg}.

dTavg/dt is the rate of change of T_{avg}

B 3.3 INSTRUMENTATION

B 3.3.1 Reactor Protection System (RPS) Instrumentation

BASES

BACKGROUND

The RPS initiates a unit shutdown, based on the values of selected unit parameters, to protect against violating the core fuel design limits and Reactor Coolant System (RCS) pressure boundary during anticipated operational occurrences (AOOs) and to assist the Engineered Safety Features (ESF) Systems in mitigating accidents.

The protection and monitoring systems have been designed to assure safe operation of the reactor. This is achieved by specifying limiting safety system settings (LSSS) in terms of parameters directly monitored by the RPS, as well as specifying LCOs on other reactor system parameters and equipment performance.

The LSSS, defined in this specification as the Allowable Value, in conjunction with the LCOs, establish the threshold for protective system action to prevent exceeding acceptable limits during Design Basis Accidents (DBAs).

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 100 criteria during AOOs.

Accidents are events that are analyzed even though they are not expected to occur during the unit life. The acceptable limit

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during accidents is that offsite dose shall be maintained within an acceptable fraction of 10 CFR 100 limits. Different accident categories are allowed a different fraction of these limits, based on probability of occurrence. 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 described in FSAR, Chapter 7 (Ref. 1), and as identified below:

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

2. Nuclear Instrumentation System (NIS), field contacts, and protection channels: 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 initiation relay logic, including input, logic, and output: initiates proper unit shutdown 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: provides 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.

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. To account for the

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calibration tolerances and instrument drift, which are assumed to occur between calibrations, statistical allowances are provided in the Allowable Values. The OPERABILITY of each transmitter or sensor can be evaluated when its "as found" calibration data are compared against its documented Allowable Value.

Signal Process Control and Protection System

Generally, three or four channels of process control equipment are used for the signal processing of unit parameters measured by the field instruments. The process control equipment provides signal conditioning, comparable output signals for instruments located on the main control board, and comparison of measured input signals with setpoints established to ensure that actuation will occur within the limits assumed in the accident analyses (Ref. 3). If the measured value of a unit parameter exceeds the predetermined setpoint, an output from a bistable is forwarded to the RPS relay logic. Channel separation is maintained up to and through the actuation logic. However, not all unit parameters require four channels of sensor measurement and signal processing. Some unit parameters provide input only to the RPS relay logic, while others provide input to the RPS relay logic, the main control board, the unit computer, and one or more control systems.

Generally, if a parameter is used only for input to the protection circuits, three channels with a two-out-of-three logic are sufficient to provide the required reliability and redundancy. If one channel fails in a direction that would not result in a partial Function trip, the Function is still OPERABLE with a two-out-of-two logic. If one channel fails, such that a partial Function trip occurs, a trip will not occur and the Function is still OPERABLE with a one-out-of-two logic.

Generally, if a parameter is used for input to the RPS relay logic and a control function, four channels with a two-out-of-four logic are sufficient to provide the required reliability and redundancy. The circuit must be able to withstand both an input failure to the control system, which may then require the protection function actuation, and a single

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failure in the other channels providing the protection function actuation. Again, a single failure will neither cause nor prevent the protection function actuation. These requirements are described in IEEE-279-1968 (Ref. 4). The actual number of channels required for each unit parameter is specified in Reference 1 and discussed later in these Technical Specification Bases.

Two logic channels are required to ensure no single random failure of a logic channel will disable the RPS. The logic channels are designed such that testing required while the reactor is at power may be accomplished without causing trip.

Trip Setpoints and Allowable Values

The following describes the relationship between the safety limit, analytical limit, allowable value and channel component calibration acceptance criteria:

a. A Safety Limit (SL) is a limit on the combination of THERMAL POWER, RCS highest loop average temperature, and RCS pressure needed to protect the integrity of physical barriers that guard against the uncontrolled release of radioactivity (i.e., fuel, fuel cladding, RCS pressure boundary and containment). The safety limits are identified in Technical Specification 2.0, Safety Limits (SLs).

b. An Analytical Limit (AL) is the trip actuation point used as an input to the accident analyses presented in FSAR, Chapter 14 (Ref. 3). Analytical limits are developed from event analyses models which consider parameters such as process delays, rod insertion times, reactivity changes, instrument response times, etc. An analytical limit for a trip actuation point is established at a point that will ensure that a Safety Limit (SL) is not exceeded.

c. An Allowable Value (AV) is the limiting actuation point for the entire channel of a trip function that will ensure, within the required level of confidence, that sufficient

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allocation exists between this actual trip function actuation point and the analytical limit. The Allowable Value is more conservative than the Analytical Limit to account for instrument uncertainties that either are not present or are not measured during periodic testing. Channel uncertainties that either are not present or are not measured during periodic testing may include design basis accident temperature and radiation effects (Ref. 5) or process dependent effects. The channel allowable value for each RPS function is controlled by Technical Specifications and is listed in Table 3.3.1-1, Reactor Protection System Instrumentation.

d. Calibration acceptance criteria (i.e., setpoints) are established by plant administrative programs for the components of a channel (i.e., required sensor, alarm, interlock, display, and trip function). The calibration acceptance criteria are established to ensure, within the required level of confidence, that the Allowable Value for the entire channel will not be exceeded during the calibration interval.

A description of the methodology used to calculate the channel allowable values and calibration acceptance criteria is provided in References 6 and 8.

Setpoints in accordance with the Allowable Value ensure that SLs are not violated during AOOs (and that the consequences of DBAs will be acceptable, providing the unit is operated from within the LCOs at the onset of the AOO or DBA and the equipment functions as designed).

Each channel of the relay logic protection system can be tested on line to verify that the signal or setpoint accuracy is within the specified allowance requirements of calculations performed in accordance with Reference 6 that are based on analytical limits consistent with Reference 3. Once a designated channel is taken out of service for testing, a simulated signal is injected in place of the field instrument signal. The process equipment for

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the channel in test is then tested, verified, and calibrated. SRs for the channels are specified in the SRs section.

The Allowable Values listed in Table 3.3.1-1 and the Trip Setpoints calculated to ensure that Allowable Values are not exceeded during the calibration interval are based on the methodology described in Reference 6, which incorporates all of the known uncertainties applicable for each channel. All field sensors and signal processing equipment for these channels are assumed to operate within the allowances of these uncertainty magnitudes.

Relay Logic Protection System

Relay logic is used for the decision logic processing of outputs from the signal processing equipment bistables. To meet the redundancy requirements, two trains of relay logic, each performing the same functions, are provided. If one train is taken out of service for maintenance or test purposes, the second train will provide reactor trip and/or ESF actuation for the unit. If both trains are taken out of service or placed in test, a reactor trip will result. Each train is packaged in its own cabinet for physical and electrical separation to satisfy separation and independence requirements. The system has been designed to trip in the event of a loss of power, directing the unit to a safe shutdown condition.

The relay logic performs the decision logic for actuating a reactor trip or ESF actuation, generates the electrical output signal that will initiate the required trip or actuation, and provides the status, permissive, and annunciator output signals to the control room.

The bistable outputs from the signal processing equipment are sensed by the relay logic equipment and combined into logic matrices that represent combinations indicative of various unit upset and accident transients. If a required logic matrix combination is completed, the system will initiate a reactor trip or send actuation signals via master and slave relays to those components whose aggregate Function best serves to alleviate the

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condition and restore the unit to a safe condition. Examples are given in the Applicable Safety Analyses, LCO, and Applicability sections of this Bases.

Reactor Trip Breakers

The RTBs are in the electrical power supply line from the control rod drive motor generator set power supply to the CRDMs. Opening of the RTBs interrupts power to the CRDMs, which allows the shutdown rods and control rods to fall into the core by gravity. Each RTB is equipped with a bypass breaker to allow testing of the RTB while the unit is at power. During normal operation the output from the reator protection system is a voltage signal that energizes the undervoltage coils in the RTBs and bypass breakers, if in use. When the required logic matrix combination is completed, the reator protection system output voltage signal is removed, the undervoltage coils are de-energized, the breaker trip lever is actuated by the de-energized undervoltage coil, and the RTBs and bypass breakers are tripped open. This allows the shutdown rods and control rods to fall into the core. In addition to the de-energization of the undervoltage coils, each breaker is also equipped with a shunt trip device that is energized to trip the breaker open upon receipt of a reactor trip signal from the reactor protection system. Either the undervoltage coil or the shunt trip mechanism is sufficient by itself, thus providing a diverse trip mechanism.

There are two reactor trip breakers in series so that opening either will interrupt power to the control rod drive mechanisms (CRDMs) and allow the rod cluster control assemblies (RCCAs), or "rods," to fall into the core and shut down the reactor. Each reactor trip breaker has a parallel reactor trip bypass breaker that is normally open. This feature allows testing of the reactor trip breakers at power. A trip signal from RPS logic train A will trip reactor trip breaker A and reactor trip bypass breaker B; and, a trip signal from logic train B will trip reactor trip breaker B and reactor trip bypass breaker A. During normal operation, both reactor trip breakers are closed and both reactor trip bypass breakers are open. An interlock trips both reactor trip bypass breakers if an attempt is made to close a

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BACKGROUND (continued)

reactor trip bypass breaker when the other reactor trip bypass breaker is already closed.

A trip breaker train consists of both the reactor trip breaker and reactor trip bypass breaker associated with a single RPS logic train if the breaker is racked in, closed, and capable of supplying power to the CRD System. Thus, the train consists of the main breaker; or, the main breaker and bypass breaker associated with this same RPS logic train if both the breaker and bypass are racked in, closed, and capable of supplying power to the CRD System.

The RPS decision logic Functions are described in the functional diagrams included in Reference 2. In addition to the reactor protection and ESFAS trips, the various "permissive interlocks" that are associated with unit conditions are also described.

When any one RPS train is taken out of service for testing, the other train is capable of providing unit monitoring and protection until the testing has been completed.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The RPS functions to maintain the Safety Limits (SLs) during all Abnormal Operating Occurences (AOOs) and mitigates the consequences of DBAs in all MODES in which the Rod Control system is capable of rod withdrawal and one or more rods not fully inserted.

Each of the analyzed accidents and transients can be detected by one or more RPS Functions. The accident analysis described in Reference 3 takes credit for most RPS trip Functions. RPS trip Functions not specifically credited in the accident analysis are qualitatively credited in the safety analysis and the NRC staff approved licensing basis. These RPS trip Functions may provide protection for conditions that do not require dynamic transient analysis to demonstrate Function performance. They may also serve as backups to RPS trip Functions that were credited in the accident analysis.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The LCO requires all instrumentation performing an RPS Function, listed in Table 3.3.1-1 in the accompanying LCO, to be OPERABLE. 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, two channels of Manual Reactor Trip, and two trains in each Automatic Trip Logic Function. Generally, four OPERABLE instrumentation channels in a two-out-of-four configuration are required when one RPS channel is also used as a control system input. Isolation amplifiers prevent a control system failure from affecting the protection system (Ref. 1). This configuration accounts for the possibility of the shared channel failing in such a manner that it creates a transient that requires RPS action. In this case, the RPS will still provide protection, even with random failure of one of the other three protection channels. Three OPERABLE instrumentation channels in a two-out-of-three configuration are generally required when there is no potential for control system and protection system interaction that could simultaneously create a need for RPS trip and disable one RPS channel. The two-out-of-three and two-out-of-four configurations allow one channel to be tripped during maintenance or testing without causing a reactor trip. Specific exceptions to the above general philosophy exist and are discussed below.

Reactor Protection System Functions

The safety analyses and OPERABILITY requirements applicable to each RPS Function are discussed below:

1. Manual Reactor Trip

The Manual Reactor Trip ensures that the control room operator can initiate a reactor trip at any time by using either of two reactor trip push buttons in the control room. A Manual Reactor Trip accomplishes the same results as any one of the automatic trip Functions. It is used by

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

the reactor operator to shut down the reactor whenever any parameter is rapidly trending toward its Trip Setpoint.

The LCO requires two Manual Reactor Trip channels to be OPERABLE. Each channel is controlled by a manual reactor trip push button. Each channel activates the reactor trip breaker in both trains. Two independent channels are required to be OPERABLE so that no single random failure will disable the Manual Reactor Trip Function.

In MODE 1 or 2, manual initiation of a reactor trip must be OPERABLE. These are the MODES in which the shutdown rods and/or control rods are partially or fully withdrawn from the core. In MODE 3, 4, or 5, the manual initiation Function must also be OPERABLE if the shutdown rods or control rods are withdrawn or the Rod Control System is capable of withdrawing the shutdown rods or the control rods. In this condition, inadvertent control rod withdrawal is possible. In MODE 3, 4, or 5, manual initiation of a reactor trip does not have to be OPERABLE if the Rod Control System is not capable of withdrawing the shutdown rods or control rods and if all rods are fully inserted. If the rods cannot be withdrawn from the core, or all of the rods are inserted there is no need to be able to trip the reactor. In MODE 6, neither the shutdown rods nor the control rods are permitted to be withdrawn and the CRDMs are disconnected from the control rods and shutdown rods. Therefore, the manual initiation Function is not required.

2. Power Range Neutron Flux

The NIS power range detectors are located external to the reactor vessel and measure neutrons leaking from the core. The NIS power range detectors provide input to the Rod Control System and Turbine Control System. Four channels of NIS are required because the actuation logic must be able to withstand an input failure to the control system and a single failure in the other three channels providing the protection function actuation. Note that this Function

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

also provides a signal to prevent automatic and manual rod withdrawal prior to initiating a reactor trip. Limiting further rod withdrawal may terminate the transient and eliminate the need to trip the reactor.

a. Power Range Neutron Flux-High

The Power Range Neutron Flux-High trip Function ensures that protection is provided, from all power levels, against a positive reactivity excursion leading to DNB during power operations. These can be caused by rod withdrawal or reductions in RCS temperature.

The LCO requires all four of the Power Range Neutron Flux-High channels to be OPERABLE. These channels are considered OPERABLE during required Surveillance tests that require insertion of a test signal if the channel remains untripped and capable of tripping due to an increasing neutron flux signal.

In MODE 1 or 2, when a positive reactivity excursion could occur, the Power Range Neutron Flux-High trip must be OPERABLE. This Function will terminate the reactivity excursion and shut down the reactor prior to reaching a power level that could damage the fuel. In MODE 3, 4, 5, or 6, the NIS power range detectors cannot detect neutron levels in this range. In these MODES, the Power Range Neutron Flux-High does not have to be OPERABLE because the reactor is shut down and reactivity excursions into the power range are extremely unlikely. Other RPS Functions and administrative controls provide protection against reactivity additions when in MODE 3, 4, 5, or 6.

The Power Range Neutron Flux-High Allowable Value and Trip Setpoint are in accordance with Consolidated Edison Company of New York, Inc. Indian Point Nuclear Generating Station Unit No. 3 Plant Manual Volume VI:

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Precautions, Limitations, and Setpoints, March 1975 (Ref. 8).

b. Power Range Neutron Flux-Low

The LCO requirement for the Power Range Neutron Flux-Low trip Function ensures that protection is provided against a positive reactivity excursion from low power or subcritical conditions.

The LCO requires all four of the Power Range Neutron Flux-Low channels to be OPERABLE.

In MODE 1, below the Power Range Neutron Flux (P-10 setpoint), and in MODE 2, the Power Range Neutron Flux-Low trip must be OPERABLE. This Function may be manually blocked by the operator when two out of four power range channels are greater than approximately 10% RTP (P-10 setpoint). This Function is automatically unblocked when three out of four power range channels are below the P-10 setpoint. Above the P-10 setpoint, positive reactivity additions are mitigated by the Power Range Neutron Flux-High trip Function.

In MODE 3, 4, 5, or 6, the Power Range Neutron Flux-Low trip Function does not have to be OPERABLE because the reactor is shut down and the NIS power range detectors cannot detect neutron levels in this range. Other RPS trip Functions and administrative controls provide protection against positive reactivity additions or power excursions in MODE 3, 4, 5, or 6.

The Power Range Neutron Flux-Low Allowable Value and Trip Setpoint are in accordance with Consolidated Edison Company of New York, Inc. Indian Point Nuclear Generating Station Unit No. 3 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, March 1975 (Ref. 8).

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

3. Intermediate Range Neutron Flux

The Intermediate Range Neutron Flux trip Function ensures that protection is provided against an uncontrolled RCCA bank rod withdrawal accident from a subcritical condition during startup. This trip Function provides redundant protection to the Power Range Neutron Flux – Low Setpoint trip Function. Therefore, only one of the two channels of Intermediate Range Neutron Flux is Required to be OPERABLE in the Applicable MODES. Either of the two channels can be used to satisfy this requirement. The NIS intermediate range detectors are located external to the reactor vessel and measure neutrons leaking from the core. The NIS intermediate range detectors do not provide any input to control systems. Note that this Function also provides a signal to prevent automatic and manual rod withdrawal prior to initiating a reactor trip. Limiting further rod withdrawal may terminate the transient and eliminate the need to trip the reactor.

The LCO requires one channel of Intermediate Range Neutron Flux to be OPERABLE. One OPERABLE channel is sufficient to provide redundant protection to the Power Range Neutron Flux – Low Setpoint trip Function.

Table 3.3.1-1 identifies the Technical Specification Allowable Value for this trip function as not applicable (NA) because 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 is 25% RTP. This allowable value was established based on Indian Point Nuclear Generating Station Unit No. 3 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, March 1975, (Ref. 8).

Because this trip Function is important only during startup, there is generally no need to disable channels for testing while the Function is required to be OPERABLE. Therefore, a third channel is unnecessary.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The Intermediate Range Neutron Flux trip must be OPERABLE in MODE 1 below the P-10 setpoint, and in MODE 2 above the P-6 setpoint, when there is a potential for an uncontrolled RCCA bank rod withdrawal accident during reactor startup. Above the P-10 setpoint, the Power Range Neutron Flux-High Setpoint trip provides core protection for a rod withdrawal accident. In MODE 2, below the P-6 setpoint, the source Range Neutron Flux Trip provides backup core protection for reactivity accidents. In MODE 3, 4, or 5, the Intermediate Range Neutron Flux trip does not have to be OPERABLE because the control rods must be fully inserted and only the shutdown rods may be withdrawn. The reactor cannot be started up in this condition. The core also has the required SDM to mitigate the consequences of a positive reactivity addition accident. In MODE 6, all rods are fully inserted and the core has a required increased SDM. Also, the NIS intermediate range detectors cannot detect neutron levels present in this MODE.

4. Source Range Neutron Flux

The LCO requirement for the Source Range Neutron Flux trip Function ensures that protection is provided against an uncontrolled RCCA bank rod withdrawal accident from a subcritical condition during startup. This trip Function provides redundant protection to the Power Range Neutron Flux-Low trip Function. Therefore, only one of the two channels of Source Range Neutron Flux is Required to be OPERABLE in the Applicable MODES. Either of the two channels can be used to satisfy this requirement. In MODES 3, 4, and 5, administrative controls also prevent the uncontrolled withdrawal of rods. The NIS source range detectors are located external to the reactor vessel and measure neutrons leaking from the core. The NIS source range detectors do not provide any inputs to control systems. The source range trip is the only RPS automatic protection function required in MODES 3, 4, and 5 when rods are capable of withdrawal and one or more rods are not fully inserted. Therefore, the functional capability at the specified Allowable Values is assumed to be available.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The LCO requires one channel of Source Range Neutron Flux to be OPERABLE. One OPERABLE channel is sufficient to provide redundant protection to the Power Range Neutron Flux – Low Setpoint trip Function.

Table 3.3.1-1 identifies the Technical Specification Allowable Value for this trip function as not applicable (NA) because 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 is 1.0 E+5 counts per second. This allowable value was established based on Indian Point Nuclear Generating Station Unit No. 3 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, March 1975, (Ref. 8).

The Source Range Neutron Flux Function provides protection for control rod withdrawal from subcritical. The Function also provides visual neutron flux indication in the control room.

In MODE 2 when below the P-6 setpoint and in MODES 3, 4, and 5, when there is a potential for an uncontrolled RCCA bank withdrawal accident, the Source Range Neutron Flux trip must be OPERABLE. Above the P-6 setpoint, the Intermediate Range Neutron Flux trip and the Power Range Neutron Flux – Low trip will provide core protection for reactivity accidents. Above the P-6 setpoint, the NIS source range detectors are de-energized.

In MODEs 3, 4, and 5 with all rods fully inserted and the Rod Control System not capable of rod withdrawal, and in MODE 6, the outputs of this function to the RPS logic are not required to be OPERABLE. The requirements for the NIS source range detectors in MODE 6 are addressed in LCO 3.9.2, "Nuclear Instrumentation."

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

5. Overtemperature ΔT

The Overtemperature ΔT trip Function is provided to ensure that the design limit DNBR is met. This trip Function also limits the range over which the Overpower ΔT trip Function must provide protection. The inputs to the Overtemperature ΔT trip include pressure, coolant temperature, axial power distribution, and reactor power as indicated by loop ΔT assuming full reactor coolant flow. Protection from violating the DNBR limit is assured for those transients that are slow with respect to delays from the core to the measurement system. The Overtemperature ΔT trip Function uses each loop's ΔT as a measure of reactor power and is compared with a setpoint that is automatically varied with the following parameters:

- reactor coolant average temperature – the Trip Setpoint is varied to correct for changes in coolant density and specific heat capacity with changes in coolant temperature;

- pressurizer pressure – the Trip Setpoint is varied to correct for changes in system pressure; and

- axial power distribution – f(ΔI), the Trip Setpoint is varied to account for imbalances in the axial power distribution as detected by the NIS upper and lower power range detectors. If axial peaks are greater than the Technical Specification limit, as indicated by the difference between the upper and lower NIS power range detectors, the Trip Setpoint is reduced in accordance with Note 1 of Table 3.3.1-1.

Dynamic compensation is included for system piping delays from the core to the temperature measurement system.

The Overtemperature ΔT trip Function is calculated for each loop as described in Note 1 of Table 3.3.1-1. Trip occurs if Overtemperature ΔT is indicated in two loops. The pressure and temperature signals are used for other control

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

functions. Therefore, the actuation logic is designed to withstand an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Note that this Function also provides a signal to generate a turbine runback prior to reaching the Trip Setpoint. A turbine runback will reduce turbine power and reactor power. A reduction in power will normally alleviate the Overtemperature ΔT condition and may prevent a reactor trip.

The LCO requires all four channels of the Overtemperature ΔT trip Function to be OPERABLE. Note that the Overtemperature ΔT Function receives input from channels shared with other RPS Functions. Failures that affect multiple Functions require entry into the Conditions applicable to all affected Functions.

In MODE 1 or 2, the Overtemperature ΔT trip must be OPERABLE to prevent DNB. In MODE 3, 4, 5, or 6, this trip Function does not have to be OPERABLE because the reactor is not operating and there is insufficient heat production to be concerned about DNB.

6. Overpower ΔT

The Overpower ΔT trip Function ensures that protection is provided to ensure the integrity of the fuel (i.e., no fuel pellet melting and less than 1% cladding strain) under all possible overpower conditions. This trip Function also limits the required range of the Overtemperature ΔT trip Function and provides a backup to the Power Range Neutron Flux–High Setpoint trip. The Overpower ΔT trip Function ensures that the allowable heat generation rate (kW/ft) of the fuel is not exceeded. It uses the ΔT of each loop as a measure of reactor power with a setpoint that is automatically varied with the following parameters:

- reactor coolant average temperature – the Trip Setpoint is varied to correct for changes in coolant density

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

and specific heat capacity with changes in coolant temperature; and

- rate of change of reactor coolant average temperature – including a constant determined by dynamic considerations that provides compensation for the delays between the core and the temperature measurement system.

The Overpower ΔT trip Function is calculated for each loop as per Note 2 of Table 3.3.1-1. Trip occurs if Overpower ΔT is indicated in two loops. The temperature signals are used for other control functions. Therefore, the actuation logic is designed to withstand an input failure to the control system, which may then require the protection function actuation and a single failure in the remaining channels providing the protection function actuation. Note that this Function also provides a signal to generate a turbine runback prior to reaching the Allowable Value. A turbine runback will reduce turbine power and reactor power. A reduction in power will normally alleviate the Overpower ΔT condition and may prevent a reactor trip.

The LCO requires four channels of the Overpower ΔT trip Function to be OPERABLE. Note that the Overpower ΔT trip Function receives input from channels shared with other RPS Functions. Failures that affect multiple Functions require entry into the Conditions applicable to all affected Functions.

In MODE 1 or 2, the Overpower ΔT trip Function must be OPERABLE. These are the only times that enough heat is generated in the fuel to be concerned about the heat generation rates and overheating of the fuel. In MODE 3, 4, 5, or 6, this trip Function does not have to be OPERABLE because the reactor is not operating and there is insufficient heat production to be concerned about fuel overheating and fuel damage.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

7. Pressurizer Pressure

The same sensors provide input to the Pressurizer Pressure – High and – Low trips and the Overtemperature ΔT trip. The Pressurizer Pressure channels are also used to provide input to the Pressurizer Pressure Control System. Therefore, the actuation logic is designed to withstand an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Note that the plant design and this LCO require 4 channels for the Pressurizer Pressure– Low trips but requires only 3 channels of Pressurizer Pressure – High. This difference recognizes the role of pressurizer code safety valves in response to a high pressure condition.

a. Pressurizer Pressure-Low

The Pressurizer Pressure – Low trip Function ensures that protection is provided against violating the DNBR limit due to low pressure.

The LCO requires four channels of Pressurizer Pressure – Low to be OPERABLE.

In MODE 1, when DNB is a major concern, the Pressurizer Pressure – Low trip must be OPERABLE. This trip Function is automatically enabled on increasing power by the P-7 interlock (NIS power range P-10 or turbine first stage pressure greater than approximately 10% of full power equivalent). On decreasing power, this trip Function is automatically blocked below P-7. Below the P-7 setpoint, no conceivable power distributions can occur that would cause DNB concerns.

b. Pressurizer Pressure-High

The Pressurizer Pressure – High trip Function ensures that protection is provided against overpressurizing

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

the RCS. This trip Function operates in conjunction with the pressurizer relief and safety valves to prevent RCS overpressure conditions.

The LCO requires three channels of the Pressurizer Pressure-High to be OPERABLE.

The Pressurizer Pressure-High Allowable Value is selected to be below the pressurizer safety valve actuation pressure and above the power operated relief valve (PORV) setting. This setting minimizes challenges to safety valves while avoiding unnecessary reactor trip for those pressure increases that can be controlled by the PORVs.

In MODE 1 or 2, the Pressurizer Pressure-High trip must be OPERABLE to help prevent RCS overpressurization and minimize challenges to the safety valves. In MODE 3, 4, 5, or 6, the Pressurizer Pressure-High trip Function does not have to be OPERABLE because transients that could cause an overpressure condition will be slow to occur. Therefore, the operator will have sufficient time to evaluate unit conditions and take corrective actions. Additionally, low temperature overpressure protection systems provide overpressure protection when RCS temperature is less than the LTOP arming temperature specified in LCO 3.4.12, Low Temperature Overpressure Protection (LTOP).

8. Pressurizer Water Level-High

The Pressurizer Water Level-High trip Function provides a backup signal for the Pressurizer Pressure-High trip and also provides protection against water relief through the pressurizer safety valves. These valves are designed to pass steam in order to achieve their design energy removal rate. A reactor trip is actuated prior to the pressurizer becoming water solid. The LCO requires three channels of Pressurizer Water Level-High to be OPERABLE. The

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

pressurizer level channels are used as input to the Pressurizer Level Control System. A fourth channel is not required to address control/protection interaction concerns because the level channels do not actuate the safety valves, and the high pressure reactor trip is set below the safety valve setting. Therefore, with the slow rate of charging available, pressure overshoot due to level channel failure cannot cause the safety valve to lift before reactor high pressure trip.

In MODE 1, when there is a potential for overfilling the pressurizer, the Pressurizer Water Level – High trip must be OPERABLE. This trip Function is automatically enabled on increasing power by the P-7 interlock. On decreasing power, this trip Function is automatically blocked below P-7. Below the P-7 setpoint, transients that could raise the pressurizer water level will be slow and the operator will have sufficient time to evaluate unit conditions and take corrective actions.

9. Reactor Coolant Flow-Low

a. Reactor Coolant Flow-Low (Single Loop)

The Reactor Coolant Flow – Low (Single Loop) trip Function ensures that protection is provided against violating the DNBR limit due to low flow in one or more RCS loops, while avoiding reactor trips due to normal variations in loop flow. Above the P-8 setpoint, which is approximately 50% RTP, a loss of flow in any RCS loop will actuate a reactor trip. Each RCS loop has three flow detectors to monitor flow. The flow signals are not used for any control system input.

The LCO requires three Reactor Coolant Flow – Low channels per RCS loop to be OPERABLE in MODE 1 above P-8. Each reactor coolant loop is considered to be a separate function. Therefore, separate condition entry is allowed for each loop.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

In MODE 1 above the P-8 setpoint, a loss of flow in one RCS loop could result in DNB conditions in the core. In MODE 1 below the P-8 setpoint, a loss of flow in two or more loops is required to actuate a reactor trip (Function 9.b) because of the lower power level and the greater margin to the design limit DNBR.

b. Reactor Coolant Flow-Low (Two Loops)

The Reactor Coolant Flow-Low (Two Loops) trip Function ensures that protection is provided against violating the DNBR limit due to low flow in two or more RCS loops while avoiding reactor trips due to normal variations in loop flow.

Above the P-7 setpoint and below the P-8 setpoint, a loss of flow in two or more loops will initiate a reactor trip. Each loop has three flow detectors to monitor flow. The flow signals are not used for any control system input.

The LCO requires three Reactor Coolant Flow-Low channels per loop to be OPERABLE. Each reactor coolant loop is considered to be a separate function. Therefore, separate condition entry is allowed for each loop.

In MODE 1 above the P-7 setpoint and below the P-8 setpoint, the Reactor Coolant Flow-Low (Two Loops) trip must be OPERABLE. Below the P-7 setpoint, all reactor trips on low flow are automatically blocked since no conceivable power distributions could occur that would cause a DNB concern at this low power level. Above the P-7 setpoint, the reactor trip on low flow in two or more RCS loops is automatically enabled. Above the P-8 setpoint, a loss of flow in any one loop (Function 9.a) will actuate a reactor trip because of the higher power level and the reduced margin to the design limit DNBR.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

10. Reactor Coolant Pump (RCP) Breaker Position

Both RCP Breaker Position trip Function operates to anticipate the Reactor Coolant Flow – Low trips to avoid RCS heatup that would occur before the low flow trip actuates.

a. Reactor Coolant Pump Breaker Position (Single Loop)

The RCP Breaker Position (Single Loop) trip Function ensures that protection is provided against violating the DNBR limit due to a loss of flow in one RCS loop. The position of each RCP breaker is monitored. If one RCP breaker is open above the P-8 setpoint, a reactor trip is initiated. This trip Function will generate a reactor trip before the Reactor Coolant Flow – Low (Single Loop) Trip Setpoint is reached.

The LCO requires one RCP Breaker Position channel per RCP to be OPERABLE. One OPERABLE channel is sufficient for this trip Function because the RCS Flow – Low trip alone provides sufficient protection of unit SLs for loss of flow events. The RCP Breaker Position trip serves only to anticipate the low flow trip, minimizing the thermal transient associated with loss of a pump. Each reactor coolant loop is considered to be a separate function. Therefore, separate condition entry is allowed for each loop.

This Function measures only the discrete position (open or closed) of the RCP breaker, using a position switch. Therefore, the Function has no adjustable trip setpoint with which to associate an LSSS.

In MODE 1 above the P-8 setpoint, when a loss of flow in any RCS loop could result in DNB conditions in the core, the RCP Breaker Position (Single Loop) trip must be OPERABLE. In MODE 1 below the P-8 setpoint, a loss of flow in two or more loops (Function 10.b) is required to actuate a reactor trip because of the

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

lower power level and the greater margin to the design limit DNBR.

b. Reactor Coolant Pump Breaker Position (Two Loops)

The RCP Breaker Position (Two Loops) trip Function ensures that protection is provided against violating the DNBR limit due to a loss of flow in two or more RCS loops. The position of each RCP breaker is monitored. Above the P-7 setpoint a loss of flow in two or more loops will initiate a reactor trip. This trip Function will generate a reactor trip before the Reactor Coolant Flow – Low (Two Loops) Trip Setpoint is reached.

The LCO requires one RCP Breaker Position channel per RCP to be OPERABLE. One OPERABLE channel is sufficient for this Function because the RCS Flow – Low trip alone provides sufficient protection of unit SLs for loss of flow events. The RCP Breaker Position trip serves only to anticipate the low flow trip, minimizing the thermal transient associated with loss of an RCP. Each reactor coolant loop is considered to be a separate function. Therefore, separate condition entry is allowed for each loop.

This Function measures only the discrete position (open or closed) of the RCP breaker, using a position switch. Therefore, the Function has no adjustable trip setpoint with which to associate an LSSS.

In MODE 1 above the P-7 setpoint and below the P-8 setpoint, the RCP Breaker Position (Two Loops) trip must be OPERABLE. Below the P-7 setpoint, all reactor trips on loss of flow are automatically blocked since no conceivable power distributions could occur that would cause a DNB concern at this low power level. Above the P-7 setpoint, the reactor trip on loss of flow in two RCS loops is automatically enabled. Above the P-8 setpoint, a loss of flow in any one loop

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

(Function 10.a) will actuate a reactor trip because of the higher power level and the reduced margin to the design limit DNBR.

11. Undervoltage Reactor Coolant Pumps (6.9 kV Bus)

The Undervoltage RCPs direct reactor trip Function ensures that protection is provided against violating the DNBR limit due to a loss of flow in two or more RCS loops. The voltage to each 6.9 kV bus used to power an RCP is monitored. Above the P-7 setpoint, a loss of voltage detected on two or more RCP buses will initiate a direct reactor trip. This trip Function will generate a reactor trip before the Reactor Coolant Flow – Low (Two Loops) Trip Setpoint is reached. Time delays are incorporated into the Undervoltage RCPs channels associated with the direct reactor trip and are provided to prevent reactor trips due to momentary electrical power transients.

The LCO requires one Undervoltage RCPs channel per bus to be OPERABLE.

In MODE 1 above the P-7 setpoint, the Undervoltage RCP trip must be OPERABLE. Below the P-7 setpoint, all reactor trips on loss of flow are automatically blocked since no conceivable power distributions could occur that would cause a DNB concern at this low power level. Above the P-7 setpoint, the reactor trip on loss of flow in two or more RCS loops is automatically enabled.

12. Underfrequency Reactor Coolant Pumps

The Underfrequency RCPs reactor trip Function ensures that protection is provided against violating the DNBR limit due to a loss of flow in two or more RCS loops from a major network frequency disturbance. An underfrequency condition will slow down the pumps, thereby reducing their coastdown time following a pump trip. The proper coastdown time is required so that reactor heat can be removed immediately after reactor trip. The frequency of each RCP bus is

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

monitored. A loss of frequency detected on two or more RCP buses trips all four RCPs, a condition that will initiate a reactor trip. This trip Function will generate a reactor trip before the Reactor Coolant Flow – Low (Two Loops) Trip Setpoint is reached.

The LCO requires one Underfrequency RCP channel per bus to be OPERABLE.

13. Steam Generator Water Level-Low Low

The SG Water Level – Low Low trip Function ensures that protection is provided against a loss of heat sink and actuates the AFW System prior to uncovering the SG tubes. The SGs are the heat sink for the reactor. In order to act as a heat sink, the SGs must contain a minimum amount of water. A narrow range low low level in any SG is indicative of a loss of heat sink for the reactor. The "B" channel level transmitters provide input to the SG Level Control System. This Function also performs the function of starting the AFW pumps on low low SG level.

The LCO requires three channels of SG Water Level – Low Low per SG to be OPERABLE. Each SG is considered to be a separate function. Therefore, separate condition entry is allowed for each SG.

In MODE 1 or 2, when the reactor requires a heat sink, the SG Water Level – Low Low trip must be OPERABLE. The normal source of water for the SGs is the Main Feedwater (MFW) System (not safety related). The MFW System is only in operation in MODE 1 or 2. The AFW System is the safety related backup source of water to ensure that the SGs remain the heat sink for the reactor. During normal startups and shutdowns, the AFW System provides feedwater to maintain SG level. In MODE 3, 4, 5, or 6, the SG Water Level – Low Low Function does not have to be OPERABLE because the MFW System is not in operation and the reactor is not critical. Decay heat removal is accomplished by the

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

AFW System in MODE 3 and 4 and by the Residual Heat Removal (RHR) System in MODE 4, 5, or 6.

14. Steam Generator Water Level-Low, Coincident With Steam Flow/Feedwater Flow Mismatch

SG Water Level – Low, in conjunction with the Steam Flow/Feedwater Flow Mismatch, ensures that protection is provided against a loss of heat sink and actuates the AFW System. In addition to a decreasing water level in the SG, the difference between feedwater flow and steam flow is evaluated to determine if feedwater flow is significantly less than steam flow. With less feedwater flow than steam flow, SG level will decrease at a rate dependent upon the magnitude of the difference in flow rates. The required logic is developed from two SG level channels and two Steam Flow/Feedwater Flow Mismatch channels per SG. One narrow range level channel coincident with the associated Steam Flow/Feedwater Flow Mismatch channel for the same SG (steam flow greater than feed flow) will actuate a reactor trip. This function also initiates a turbine trip if reactor power is above the P-7 setpoint.

The LCO requires two channels of SG Water Level – Low coincident with Steam Flow/Feedwater Flow Mismatch. Each SG is considered to be a separate function. Therefore, separate condition entry is allowed for each SG.

Table 3.3.1-1 identifies the Technical Specification Allowable Value for this trip function as not applicable (NA) because LCO 3.3.1, Function 13, Steam Generator Water Level-Low Low, is used to bound the analysis for a loss of feedwater event. The allowable values required for OPERABILITY of this trip function is ≥ 3.54% for steam generator level (the same allowable value as the Steam Generator Water Level-Low Low) and ≥ 1.64 E+6 pounds per hour difference for the steam flow feed flow mismatch. These allowable values are based on engineering judgement.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

In MODE 1 or 2, when the reactor requires a heat sink, the SG Water Level – Low coincident with Steam Flow/Feedwater Flow Mismatch trip must be OPERABLE. The normal source of water for the SGs is the MFW System (not safety related). The MFW System is only in operation in MODE 1 or 2. The AFW System is the safety related backup source of water to ensure that the SGs remain the heat sink for the reactor. During normal startups and shutdowns, the AFW System provides feedwater to maintain SG level. In MODE 3, 4, 5, or 6, the SG Water Level – Low coincident with Steam Flow/ Feedwater Flow Mismatch Function does not have to be OPERABLE because the MFW System is not in operation and the reactor is not critical. Decay heat removal is accomplished by the AFW System in MODE 3 and 4 and by the RHR System in MODE 4, 5, or 6. The MFW System is in operation only in MODE 1 or 2 and, therefore, this trip Function need only be OPERABLE in these MODES.

15. Turbine Trip – Low Auto-Stop Oil Pressure

The Turbine Trip – Low Auto-Stop Oil Pressure trip Function anticipates the loss of heat removal capabilities of the secondary system following a turbine trip. This trip Function acts to minimize the pressure/temperature transient on the reactor. Any turbine trip from a power level below the P-7 setpoint, approximately 10% power, will not actuate a reactor trip. Three pressure switches monitor the control oil pressure in the Turbine Control System. A low pressure condition sensed by two-out-of-three pressure switches will actuate a reactor trip. These pressure switches do not provide any input to the control system. The unit is designed to withstand a complete loss of load and not sustain core damage or challenge the RCS pressure limitations. Core protection is provided by the Pressurizer Pressure – High trip Function and RCS integrity is ensured by the pressurizer safety valves.

The LCO requires three channels of Turbine Trip – Low Fluid Oil Pressure to be OPERABLE in MODE 1 above P-7.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Below the P-7 setpoint, a turbine trip does not actuate a reactor trip. In MODE 1 (below P-7 setpoint), 2, 3, 4, 5, or 6, there is no potential for a turbine trip that would require a reactor trip, and the Turbine Trip – Low Auto-Stop Oil Pressure trip Function does not need to be OPERABLE.

16. Safety Injection Input from Engineered Safety Feature Actuation System

The SI Input from ESFAS ensures that if a reactor trip has not already been generated by the RPS, the ESFAS automatic actuation logic will initiate a reactor trip signal upon any signal that initiates SI. This is a condition of acceptability for the LOCA. However, other transients and accidents take credit for varying levels of ESF performance and rely upon rod insertion, except for the most reactive rod that is assumed to be fully withdrawn, to ensure reactor shutdown. Therefore, a reactor trip is initiated every time an SI signal is present.

Trip Setpoint and Allowable Values are not applicable to this Function. The SI Input is provided by relay in the ESFAS. Therefore, there is no measurement signal with which to associate an LSSS.

The LCO requires two trains of SI Input from ESFAS to be OPERABLE in MODE 1 or 2.

A reactor trip is initiated every time an SI signal is present. Therefore, this trip Function must be OPERABLE in MODE 1 or 2, when the reactor is critical, and must be shut down in the event of an accident. In MODE 3, 4, 5, or 6, the reactor is not critical, and this trip Function does not need to be OPERABLE.

17. Reactor Trip System Interlocks

Reactor protection interlocks are provided to ensure reactor trips are in the correct configuration for the current unit status. They back up operator actions to

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

ensure protection system Functions are not bypassed during unit conditions under which the safety analysis assumes the Functions are not bypassed. Therefore, the interlock Functions do not need to be OPERABLE when the associated reactor trip functions are outside the applicable MODES. These are:

a. Intermediate Range Neutron Flux, P-6

The Intermediate Range Neutron Flux, P-6 interlock is actuated when any NIS intermediate range channel goes approximately one decade above the minimum channel reading. If both channels drop below the setpoint, the permissive will automatically be defeated. Manual defeat of the P-6 interlock can be accomplished at any time by simultaneous actuation of both Reset pushbuttons. The LCO requirement for the P-6 interlock ensures that the following Functions are performed:

- on increasing power, the P-6 interlock allows the manual block of the NIS Source Range, Neutron Flux reactor trip. This prevents a premature block of the source range trip and allows the operator to ensure that the intermediate range is OPERABLE prior to leaving the source range. The source range trip is blocked by removing the high voltage to the detectors;

- on decreasing power, the P-6 interlock automatically energizes the NIS source range detectors and enables the NIS Source Range Neutron Flux reactor trip; and

The LCO requires two channels of Intermediate Range Neutron Flux, P-6 interlock to be OPERABLE in MODE 2 when below the P-6 interlock setpoint.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Above the P-6 interlock setpoint, the NIS Source Range Neutron Flux reactor trip will be blocked, and this Function will no longer be necessary.

In MODE 3, 4, 5, or 6, the P-6 interlock does not have to be OPERABLE because the NIS Source Range is providing core protection if required.

b. Low Power Reactor Trips Block, P-7

The Low Power Reactor Trips Block, P-7 interlock, is actuated by input from either the Power Range Neutron Flux, P-10, or the Turbine First Stage Pressure. The LCO requirement for the P-7 interlock ensures that the following Functions are performed:

(1) on increasing power, the P-7 interlock (i.e., 2 of 4 Power Range channels increasing above the P-10 (Function 17.d) setpoint or 1 of 2 Turbine First Stage Pressure (Function 17.e) setpoint) automatically enables reactor trips on the following Functions:

- Pressurizer Pressure – Low;
- Pressurizer Water Level – High;
- Reactor Coolant Flow – Low (Two Loops);
- RCPs Breaker Open (Two Loops);
- Undervoltage RCPs; and
- Turbine Trip.

These reactor trips are only required when operating above the P-7 setpoint (approximately 10% power). The reactor trips provide protection against violating the DNBR limit. Below the P-7 setpoint, the RCS is capable of

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providing sufficient natural circulation without any RCP running.

(2) on decreasing power, the P-7 interlock (i.e., 3 of 4 Power Range channels decreasing below the P-10 (Function 17.d) setpoint and 2 of 2 Turbine First Stage Pressure channels decreasing below the Turbine First Stage Pressure (Function 17.e) setpoint) automatically blocks reactor trips on the following Functions:

- Pressurizer Pressure – Low;
- Pressurizer Water Level – High;
- Reactor Coolant Flow – Low (Two Loops);
- RCP Breaker Position (Two Loops);
- Undervoltage RCPs; and
- Turbine Trip.

An Allowable Value is not applicable to the P-7 interlock because it is a logic Function. The Allowable Value for the P-10 interlock (Function 17.d) governs input from the Power Range instruments and the Allowable Value for the Turbine First Stage Pressure interlock (Function 17.e) governs input for turbine power.

The P-7 interlock is a logic Function with train and not channel identity. Therefore, the LCO requires one channel per train (i.e., two trains) of Low Power Reactor Trips Block, P-7 interlock to be OPERABLE in MODE 1.

The low power trips are blocked below the P-7 setpoint and unblocked above the P-7 setpoint. In MODE 2, 3,

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4, 5, or 6, this Function does not have to be OPERABLE because the interlock performs its Function when power level drops below 10% power, which is in MODE 1.

c. Power Range Neutron Flux, P-8

The Power Range Neutron Flux, P-8 interlock is actuated at approximately 50% power as determined by NIS power range detectors. The P-8 interlock automatically enables the Reactor Coolant Flow – Low (Single Loop) and RCP Breaker Position (Single Loop) reactor trips on low flow in one or more RCS loops whenever at least 2 of 4 the Power Range instruments increase to above the P-8 setpoint. The LCO requirement for this trip Function ensures that protection is provided against a loss of flow in any RCS loop that could result in DNB conditions in the core when greater than approximately 50% power. On decreasing power, the reactor trip on low flow in any loop is automatically blocked whenever at least 3 of 4 the Power Range instruments decrease to below the P-8 setpoint.

The LCO requires four channels of Power Range Neutron Flux, P-8 interlock to be OPERABLE in MODE 1.

In MODE 1, a loss of flow in one RCS loop could result in DNB conditions, so the Power Range Neutron Flux, P-8 interlock must be OPERABLE. In MODE 2, 3, 4, 5, or 6, this Function does not have to be OPERABLE because the core is not producing sufficient power to be concerned about DNB conditions.

d. Power Range Neutron Flux, P-10

The Power Range Neutron Flux, P-10 interlock is actuated at approximately 10% power, as determined by two-out-of-four NIS power range detectors. If power level falls below 10% RTP on 3 of 4 channels, the nuclear instrument trips will be automatically

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

unblocked. The LCO requirement for the P-10 interlock ensures that the following Functions are performed:

- on increasing power, the P-10 interlock allows the operator to manually block the Intermediate Range Neutron Flux reactor trip;
- on increasing power, the P-10 interlock allows the operator to manually block the Power Range Neutron Flux – Low reactor trip;
- on increasing power, the P-10 interlock automatically provides a backup signal to block the Source Range Neutron Flux reactor trip by de-energizing the NIS source range detectors;
- the P-10 interlock provides one of the two inputs to the P-7 interlock; and
- on decreasing power, the P-10 interlock automatically enables the Power Range Neutron Flux – Low reactor trip and the Intermediate Range Neutron Flux reactor trip (and rod stop).

The LCO requires four channels of Power Range Neutron Flux, P-10 interlock to be OPERABLE in MODE 1 or 2.

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.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

e. Turbine First Stage Pressure

The Turbine First Stage Pressure interlock is actuated when the pressure in the first stage of the high pressure turbine is greater than approximately 10% of the rated full power pressure. 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 Impulse Pressure, input to the P-7 interlock, to be OPERABLE in MODE 1.

The Turbine First Stage Pressure 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 individual trip mechanisms. 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.

The LCO requires two OPERABLE trains of trip breakers. Two OPERABLE trains ensure no single random failure can disable the RPS trip capability. When a reactor trip breaker is being tested, both reactor trip breaker and the reactor trip bypass breaker associated with the RPS

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

logic train not in test are closed. In this configuration, a single failure in the RPS logic train not in test could disable RPS trip capability; therefore, limits on the duration of testing are established.

These trip Functions must be OPERABLE in MODE 1 or 2 when the reactor is critical. In MODE 3, 4, or 5, these RPS trip Functions must be OPERABLE when the Rod Control System is capable of rod withdrawal and one or more rods are not fully inserted.

19. Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms

The LCO requires both the Undervoltage and Shunt Trip Mechanisms to be OPERABLE for each RTB that is in service. The trip mechanisms are not required to be OPERABLE for trip breakers that are open, racked out, incapable of supplying power to the Rod Control System, or declared inoperable under Function 18 above. OPERABILITY of both trip mechanisms on each breaker ensures that no single trip mechanism failure will prevent opening any breaker on a valid signal.

These trip Functions must be OPERABLE in MODE 1 or 2 when the reactor is critical. In MODE 3, 4, or 5, these RPS trip Functions must be OPERABLE when the Rod Control System is capable of rod withdrawal and one or more rods are not fully inserted.

20. Automatic Trip Logic

The LCO requirement for the RTBs (Functions 18 and 19) and Automatic Trip Logic (Function 20) ensures that means are provided to interrupt the power to allow the rods to fall into the reactor core. Each RTB is equipped with a bypass breaker (RTBB) to allow testing of the trip breaker while the unit is at power. Each RTB and RTBB is equipped with

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

an undervoltage coil and a shunt trip coil to trip the breaker open when needed. The reactor trip signals generated by the RPS Automatic Trip Logic cause the RTBs and associated bypass breakers to open and shut down the reactor.

The LCO requires two trains of RPS Automatic Trip Logic to be OPERABLE. Having two OPERABLE channels ensures that random failure of a single logic channel will not prevent reactor trip.

These trip Functions must be OPERABLE in MODE 1 or 2 when the reactor is critical. In MODE 3, 4, or 5, these RPS trip Functions must be OPERABLE when the Rod Control System is capable of rod withdrawal and one or more rods are not fully inserted.

The RPS instrumentation satisfies Criterion 3 of 10 CFR 50.36.

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Note 1 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 3.3.1-1.

Note 2 specifies that when a channel or train is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 8 hours, provided the associated Function(s) maintains RPS trip capability. Upon completion of the Surveillance, or expiration of the 8 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is consistent with the assumptions of the instrumentation system reliability analysis (Ref. 7). That analysis demonstrated that the 8 hour testing allowance does not significantly reduce the probability that the RPS will trip when necessary.

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ACTIONS (continued)

As noted in Reference 9, the allowance of 2 hours for test and maintenance of reactor trip breakers provided in Condition L, Note 1, is less than the 6 hour allowable out of service time and the 8 hour allowance for testing of RPS train A and train B. In practice, if the reactor trip breaker is being tested at the same time as the associated logic train, the 8 hour allowance for testing of RPS train A and train B applies to both the logic train and the reactor trip breaker. This is acceptable based on the Safety Evaluation Report for Reference 7.

In the event a channel's Trip Setpoint is found nonconservative with respect to the Allowable Value, or the transmitter, instrument loop, signal processing electronics, or bistable is found inoperable, then all affected Functions provided by that channel must be declared inoperable and the LCO Condition(s) entered for the protection Function(s) affected.

When the number of inoperable channels in a trip Function exceed those specified in one or other related Conditions associated with a trip Function, then the unit is outside the safety analysis. Therefore, LCO 3.0.3 must be immediately entered if applicable in the current MODE of operation.

A.1

Condition A applies to all RPS protection Functions. Condition A addresses the situation where one or more required channels or trains for one or more Functions are inoperable at the same time. The Required Action is to refer to Table 3.3.1-1 and to take the Required Actions for the protection functions affected. The Completion Times are those from the referenced Conditions and Required Actions.

B.1 and B.2

Condition B applies to the Manual Reactor Trip in MODE 1 or 2. This action addresses the train orientation of the relay logic for this Function. With one channel inoperable, the inoperable channel must be restored to OPERABLE status within 48 hours. In

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ACTIONS

B.1 and B.2 (continued)

this Condition, the remaining OPERABLE channel is adequate to perform the safety function.

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 applies to any inoperable Manual Reactor Trip Function if the Rod Control System is capable of rod withdrawal and one or more rods are not fully inserted.

C.1 and C.2

Condition C applies to the following reactor trip Functions in MODE 3, 4, or 5 when the Rod Control System capable of rod withdrawal and one or more rods are 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 relay 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

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ACTIONS

C.1 and C.2 (continued)

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.

The Completion Time is reasonable considering that in this Condition, the remaining OPERABLE train is adequate to perform the safety function, and given the low probability of an event occurring during this interval.

D.1.1, D.1.2, D.2.1, D.2.2, and D.3

Condition D applies to the Power Range Neutron Flux – High Function.

The NIS power range detectors provide input to the Rod Control System and, therefore, have a two-out-of-four trip logic. A known inoperable channel must be placed in the tripped condition. This results in a partial trip condition requiring only one-out-of-three logic for actuation. The 6 hours allowed to place the inoperable channel in the tripped condition is justified in WCAP-10271-P-A (Ref. 7).

In addition to placing the inoperable channel in the tripped condition, THERMAL POWER must be reduced to ≤ 75% RTP within 24 hours. Reducing the power level prevents operation of the core with radial power distributions beyond the design limits. With one of the NIS power range detectors inoperable, 1/4 of the radial power distribution monitoring capability is lost.

As an alternative to the above actions, the inoperable channel can be placed in the tripped condition within 6 hours and the QPTR monitored once every 24 hours as per SR 3.2.4.2, QPTR verification. Calculating QPTR every 24 hours compensates for the lost monitoring capability due to the inoperable NIS power range channel and allows continued unit operation at power levels

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ACTIONS

D.1.1, D.1.2, D.2.1, D.2.2, and D.3 (continued)

≥ 75% RTP. The 6 hour Completion Time and the 24 hour Frequency are consistent with LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)."

As an alternative to the above Actions, the plant must be placed in a MODE where this Function is no longer required OPERABLE. Twelve hours are allowed to place the plant in MODE 3. This is a reasonable time, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging plant systems. If Required Actions cannot be completed within their allowed Completion Times, LCO 3.0.3 must be entered.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypass condition for up to 8 hours while performing routine surveillance testing of other channels. The Note also allows placing the inoperable channel in the bypass condition to allow setpoint adjustments of other channels when required to reduce the setpoint in accordance with other Technical Specifications. The 8 hour time limit is justified in Reference 7.

Required Action D.2.2 has been modified by a Note which only requires SR 3.2.4.2 to be performed if the Power Range Neutron Flux input to QPTR becomes inoperable. Failure of a component in the Power Range Neutron Flux Channel which renders the High Flux Trip Function inoperable may not affect the capability to monitor QPTR. As such, determining QPTR using this movable incore detectors once per 24 hours may not be necessary.

E.1 and E.2

Condition E applies to the following reactor trip Functions:

- Power Range Neutron Flux – Low;
- Overtemperature ΔT;
- Overpower ΔT;
- Pressurizer Pressure – High;

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ACTIONS

E.1 and E.2 (continued)

- SG Water Level – Low Low; and

- SG Water Level – Low coincident with Steam Flow/Feedwater Flow Mismatch.

A known inoperable channel must be placed in the tripped condition within 6 hours. Placing the channel in the tripped condition results in a partial trip condition requiring only one-out-of-two logic for actuation of the two-out-of-three trips and one-out-of-three logic for actuation of the two-out-of-four trips. The 6 hours allowed to place the inoperable channel in the tripped condition is justified in Reference 7.

If the operable 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 8 hours while performing routine surveillance testing of the other channels. The 8 hour time limit is justified in Reference 7.

F.1 and F.2

Condition F applies when there are no Intermediate Range Neutron Flux trip channels OPERABLE in MODE 2 when THERMAL POWER is above the P-6 setpoint and below the P-10 setpoint. Required Actions specified in this Condition are only applicable when channel failures do not result in reactor trip. Above the P-6 setpoint and below the P-10 setpoint, the NIS intermediate range detector performs the monitoring Functions. With no intermediate range channels OPERABLE, the Required Actions are to suspend operations involving positive reactivity additions immediately. This will preclude any power level increase since there are no OPERABLE Intermediate Range Neutron Flux channels. The operator must also

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ACTIONS

F.1 and F.2 (continued)

reduce THERMAL POWER below the P-6 setpoint within two hours. Below P-6, one or both Source Range Neutron Flux channels will be able to monitor the core power level. The Completion Time of 2 hours will allow a slow and controlled power reduction to less than the P-6 setpoint and takes into account the low probability of occurrence of an event during this period that may require the protection afforded by the NIS Intermediate Range Neutron Flux trip.

G.1

Condition G applies when there are no Source Range Neutron Flux trip channels OPERABLE when in MODE 2, below the P-6 setpoint, and in MODE 3, 4, or 5 with the Rod Control capable of rod withdrawal and one or more rods not rods fully inserted. With the unit in this Condition, below P-6, the NIS source range performs the monitoring and protection functions. With both source range channels inoperable, the RTBs must be opened immediately.

H.1 and H.2

Condition H applies to the following reactor trip Functions:

- Pressurizer Pressure – Low;
- Pressurizer Water Level – High;
- Reactor Coolant Flow – Low;
- RCP Breaker Position (Two Loops);
- Undervoltage RCPs; and
- Underfrequency RCPs.

With one channel inoperable, the inoperable channel must be placed in the tripped condition within 6 hours. Placing the channel in the tripped condition results in a partial trip condition requiring only one additional channel to initiate a

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ACTIONS

H.1 and H.2 (continued)

reactor trip above the P-7 setpoint for the two loop function and above the P-8 setpoint for the single loop function. 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. The 6 hours allowed to place the channel in the tripped condition is justified in Reference 7. 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. The Reactor Coolant Flow-Low (Single Loop) reactor trip does not have to be OPERABLE below the P-8 setpoint; however, the Required Action must take the plant below the P-7 setpoint if the inoperable channel is not tripped within 6 hour because ~~of~~ the shared components between this function and the Reactor Coolant Flow-Low (Two Loop) reactor trip function.

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 H.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to 8 hours while performing routine surveillance testing of the other channels. The 8 hour time limit is justified in Reference 7.

I.1 and I.2

Condition I 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

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ACTIONS

I.1 and I.2 (continued)

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 7.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to 8 hours while performing routine surveillance testing of the other channels. The 8 hour time limit is justified in Reference 7.

J.1 and J.2

Condition J applies to Turbine Trip on Low Auto-Stop Oil Pressure. With one channel inoperable, the inoperable channel must be placed in the trip condition within 6 hours. If placed in the tripped condition, this results in a partial trip condition requiring only one additional channel to initiate a reactor trip. If the channel cannot be restored to OPERABLE status or placed in the trip condition, then power must be reduced below the P-7 setpoint within the next 6 hours. The 6 hours allowed to place the inoperable channel in the tripped condition and the 6 hours allowed for reducing power are justified in Reference 7.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to 8 hours while performing routine surveillance testing of the other channels. The 8 hour time limit is justified in Reference 7.

K.1 and K.2

Condition K applies to the SI Input from ESFAS reactor trip and the RPS Automatic Trip Logic in MODES 1 and 2. These actions address the train orientation of the RPS for these Functions. With one train inoperable, 6 hours are allowed to restore the train to OPERABLE status (Required Action K.1) or the unit must be placed in MODE 3 within the next 6 hours. The Completion Time

BASES

ACTIONS

K.1 and K.2 (continued)

of 6 hours (Required Action K.1) is reasonable considering that in this Condition, the remaining OPERABLE train is adequate to perform the safety function and given the low probability of an event during this interval. The Completion Time of 6 hours (Required Action K.2) is reasonable, based on operating experience, to reach 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 bypassing one train up to 8 hours for surveillance testing, provided the other train is OPERABLE.

L.1 and L.2

Condition L 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, 1 hour is allowed to restore the train to OPERABLE status or the unit must be placed in MODE 3 within the next 6 hours. 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. Placing the unit in MODE 3 results in ACTION C entry while RTB(s) are inoperable.

The Required Actions have been modified by two Notes. Note 1 allows one channel to be bypassed for up to 2 hours for surveillance testing, provided the other channel is OPERABLE. Note 2 allows one RTB to be bypassed for up to 2 hours for maintenance on undervoltage or shunt trip mechanisms if the other RTB train is OPERABLE. The 2 hour time limit is justified in Reference 7.

M.1 and M.2

Condition M 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

BASES

ACTIONS

M.1 and M.2 (continued)

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.

N.1 and N.2

Condition N applies to the P-7 and P-8 interlocks and the turbine first stage pressure input to P-7. 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.

O.1 and O.2

Condition O 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.

BASES

ACTIONS

0.1 and 0.2 (continued)

With the unit in MODE 3, ACTION C applies 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 or testing 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 L.

The Completion Time of 48 hours for Required Action 0.1 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.

Note that each channel of process protection supplies both train A and train B of the RPS. When testing an individual channel, the SR is not met until both train A and train B logic are tested. The CHANNEL CALIBRATION and COTs are performed in a manner that is consistent with the assumptions used in analytically calculating the required channel accuracies.

SR 3.3.1.1

Performance of the CHANNEL CHECK once every 12 hours ensures that 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

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1 (continued)

indication of excessive instrument drift in one of the channels or of something 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 checks of channels during normal operational use of the displays associated with the LCO required channels.

SR 3.3.1.2

SR 3.3.1.2 compares the calorimetric heat balance calculation to the NIS channel output every 24 hours. If the calorimetric exceeds the NIS channel output by > 2% RTP, the NIS is not declared inoperable, but must be adjusted. If the NIS channel output cannot be properly adjusted, the channel is declared inoperable.

Two Notes modify SR 3.3.1.2. The first Note indicates that the NIS channel output shall be adjusted consistent with the calorimetric results if the absolute difference between the NIS channel output and the calorimetric is > 2% RTP. The second Note clarifies that this Surveillance is required only if reactor power is ≥ 15% RTP and that 24 hours is allowed for performing the first Surveillance after reaching 15% RTP. At lower power levels, calorimetric data are inaccurate.

The Frequency of every 24 hours is adequate. It is based on unit operating experience, considering instrument reliability and operating history data for instrument drift. Together these

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.2 (continued)

factors demonstrate the change in the absolute difference between NIS and heat balance calculated powers rarely exceeds 2% in any 24 hour period.

In addition, control room operators periodically monitor redundant indications and alarms to detect deviations in channel outputs.

SR 3.3.1.3

SR 3.3.1.3 compares the incore system to the NIS channel output every 31 EFPD. If the absolute difference is ≥ 3%, the NIS channel is still OPERABLE, but must be readjusted.

If the NIS channel cannot be properly readjusted, the channel is declared inoperable. This Surveillance is performed to verify the f(ΔI) input to the overtemperature ΔT Function.

Two Notes modify SR 3.3.1.3. Note 1 indicates that the excore NIS channel shall be adjusted if the absolute difference between the incore and excore AFD is ≥ 3%. Note 2 clarifies that the Surveillance is required only if reactor power is ≥ 90% because the requirements of LCO 3.2.3, Axial Flux Difference (AFD), are relaxed significantly below 90% RTP.

The Frequency of every 31 EFPD is adequate. It is based on unit operating experience, considering instrument reliability and operating history data for instrument drift. Also, the slow changes in neutron flux during the fuel cycle can be detected during this interval.

SR 3.3.1.4

SR 3.3.1.4 is the performance of a TADOT every 31 days on a STAGGERED TEST BASIS. This test shall verify OPERABILITY by actuation of the end devices.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.4 (continued)

The RTB test shall include separate verification of the undervoltage and shunt trip mechanisms. Independent verification of RTB undervoltage and shunt trip Function is not required for the bypass breakers. No capability is provided for performing such a test at power. The independent test of the undervoltage and shunt trip function for bypass breakers is included in SR 3.3.1.14. The bypass breaker test shall include a local shunt trip. A Note has been added to indicate that this test must be performed on the bypass breaker prior to placing it in service.

The Frequency of every 31 days on a STAGGERED TEST BASIS is adequate. It is based on industry operating experience, considering instrument reliability and operating history data.

SR 3.3.1.5

SR 3.3.1.5 is the performance of an ACTUATION LOGIC TEST. The RPS relay logic is tested every 31 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 required by Table 3.31-1. The Frequency of every 31 days on a STAGGERED TEST BASIS is adequate. It is based on industry operating experience, considering instrument reliability and operating history data.

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 > 90% because

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.6 (continued)

the requirements of LCO 3.2.3, Axial Flux Difference (AFD), are relaxed significantly below 90% RTP.

The Frequency of 31 EFPD is adequate based on operating experience, considering instrument reliability and operating history data for instrument drift.

SR 3.3.1.7

SR 3.3.1.7 is the performance of a COT every 92 days.

A COT is performed on each required channel to ensure the entire channel will perform the intended Function.

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. 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 Reference 7.

SR 3.3.1.7 is modified by a Note that provides an 8 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 8 hours 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 > 8 hours this Surveillance must be performed prior to 8 hours after entry into MODE 3. The 8 hour deferral is needed because the testing required by SR 3.3.1.7 and SR 3.3.1.8 cannot be performed on the Source Range, Intermediate Range, and Power Range instruments until in the Applicable Mode and the proximity of these instruments prevents working on more than one instrument at any one time.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.7 (continued)

The Frequency of 92 days is justified in Reference 7.

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. The Frequency is modified by a Note that allows this surveillance to be satisfied if it has been performed within 92 days of the Frequencies prior to reactor startup and 16 hours after reducing power below P-10 and 8 hours after reducing power below 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 "16 hours after reducing power below P-10" (applicable to intermediate and power range low channels) and "8 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. The Frequency of every 92 days thereafter applies if the plant remains in the MODE of Applicability after the initial performances of prior to reactor startup. Additionally, this SR must be completed for the intermediate and power range low channels within 16 hours after reducing power below the P-10 setpoint and must be completed for the source range low channel within 8 hours after reducing power below the P-6 setpoint. The MODE of Applicability for this surveillance is < P-10 for the power range low and intermediate range channels and < P-6 for the source range channels. Once the unit is in MODE 3, this surveillance is no longer required. If power is to be maintained < P-10 or < P-6 for more than 8 hours, then the testing required by this surveillance must be performed prior to the expiration of the 8 and 16 hour limits. The specified Frequency provides a reasonable time to complete the required testing or place the unit in a MODE where this surveillance is no longer required.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.8 (continued)

This test ensures that the NIS source, intermediate, and power range low channels are OPERABLE prior to taking the reactor critical and within a reasonable time after reducing power into the applicable MODE (< P-10 or < P-6). The deferral of the requirement to perform this test until 8 or 16 hours after entering the Applicable condition is needed because the testing required by SR 3.3.1.7 and SR 3.3.1.8 cannot be performed on the Source Range, Intermediate Range, and Power Range instruments until in the Applicable Mode and the proximity of these instruments prevents working on more than one instrument at any one time.

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.

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 at every refueling and every 18 months for function 11. 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.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.10 (continued)

The Frequency is based on the calibration interval used for 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 SR is modified by a Note stating that neutron detectors are excluded from the CHANNEL CALIBRATION. This is needed because the 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. The CHANNEL CALIBRATION for 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 at least MODE 2 to perform the test for the intermediate range detectors and MODE 1 for the power 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.

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 is modified

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.12 (continued)

by a Note stating that this test shall include verification of the rate lag compensation for flow from the core to the RTDs. Whenever a sensing element is replaced, the next required CHANNEL CALIBRATION of resistance temperature detectors (RTD) sensors, which may consist of an inplace qualitative assessment of sensor behavior and normal calibration of the remaining adjustable devices in the channel, is accomplished by an inplace cross calibration that compares the other sensing elements with the recently installed 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.

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, and the SI Input from ESFAS. This TADOT is performed every 24 months. The test shall verify the OPERABILITY of the undervoltage and shunt trip mechanisms for the Manual Reactor Trip Function for the Reactor Trip Breakers and Reactor Trip Bypass Breakers. The Reactor Trip Bypass Breaker test shall include testing of the automatic undervoltage trip.

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.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.14 (continued)

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

SR 3.3.1.15

SR 3.3.1.15 is the performance every 24 months of a TADOT of Turbine Trip Functions. This TADOT is as described in SR 3.3.1.4. Performance of this test will ensure that the turbine trip Function is OPERABLE prior to taking the reactor critical. This test cannot be performed with the reactor at power.

REFERENCES

1. FSAR, Chapter 7.

2. FSAR, Chapter 6.

3. FSAR, Chapter 14.

4. IEEE-279-1968

5. 10 CFR 50.49.

6. Engineering Standards Manual IES-3 and IES-3B, Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3).

7. WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.

8. Consolidated Edison Company of New York, Inc. Indian Point Nuclear Generating Station Unit No. 3 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, March 1975.

9. WCAP-14384, Implementation of RPS Technical Specification Relaxation Programs, Rev. 0, January 1996.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.1:
"Reactor Protection System (RPS) Instrumentation"

PART 2:

CURRENT TECHNICAL SPECIFICATION PAGES

Annotated to show differences between CTS and ITS

CTS pages and associated TSCRs annotated for this ITS Specification :

CTS Page No.	Effective Amendment	Annotated Amendment	TSCR No.	TSCR Description	ITS Status of TSCR
2.3-1	0	0	No TSCRs	No TSCRs for this Page	N/A
2.3-2	177	177	No TSCRs	No TSCRs for this Page	N/A
2.3-3	175	175	No TSCRs	No TSCRs for this Page	N/A
2.3-4	86	86	No TSCRs	No TSCRs for this Page	N/A
2.3-5	175	175	No TSCRs	No TSCRs for this Page	N/A
2.3-6	101	101	No TSCRs	No TSCRs for this Page	N/A
2.3-7	68	68	No TSCRs	No TSCRs for this Page	N/A
3.5-1	26	26	No TSCRs	No TSCRs for this Page	N/A
3.5-2	65	65	IPN 96-124	AOT for ESF Initiation Instrumentation (Needs Supplement)	Incorporated
3.5-7	154 (9/22/98)	154	No TSCRs	No TSCRs for this Page	N/A
3.5-7	154 (9/22/98)	154	181	Amednment 181	

Technical Specification 3.3.1: "Reactor Protection System (RPS) Instrumentation"

3.5-8	154	154	No TSCRs	No TSCRs for this Page	N/A
3.5-9	154	154	No TSCRs	No TSCRs for this Page	N/A
T 3.5-2(1)	93	93	No TSCRs	No TSCRs for this Page	N/A
T 3.5-2(2)	93	93	No TSCRs	No TSCRs for this Page	N/A
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T 4.1-1(1)	170 TSCR 98-043	170 TSCR 98-043	IPN 98-043	Instrument Channel Surveillance Intervals Extended to 24 Months	Incorporated
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T 4.1-1(3)	168 TSCR 98-043	168 TSCR 98-043	IPN 98-043	Instrument Channel Surveillance Intervals Extended to 24 Months	Incorporated
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4.5-1	142	142	No TSCRs	No TSCRs for this Page	N/A

A.1

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.~~

Specification

3.3.1 ~~1.~~ Protective instrumentation for reactor trip ~~settings~~ allowable values (L.1) shall be as follows:

A. Startup protection

T3.3.1-1, #2.b ~~(1)~~ High flux, power range (low setpoint) - ≤25% of rated power. A.5

B. Core limit protection

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

T.3.3.1-1, #7.b (2) High pressurizer pressure - ~~≤2385~~ 2408.24 (L.1) psig. A.11

T3.3.1-1, #7.a (3) Low pressurizer pressure - ~~≥1800~~ 1749 (L.1) psig. A.10

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

T3.3.1-1, Note 1 $\Delta T \leq \Delta T_o [K_1 - K_2 \left(\frac{1+\tau_1 s}{1+\tau_2 s}\right) (T_{avg} - T') + K_3 (P - P') - f(\Delta I)]$ A.8.e

A.8

ΔT_o ≤ Measured full power ΔT for the channel being calibrated, °F

T_{avg} = Average Temperature for the channel being calibrated, °F (input from instrument racks)

T' = Measured full power T_{avg} for the channel being calibrated, °F

P = Pressurizer pressure, psig (input from instrument racks)

P' = 2235 psig (i.e., nominal pressurizer pressure at rated power)

K_1 ≤ 1.20 — 1.285 — L.1

K_2 = 0.0273

K_3 = 0.0013

K_1 is a constant which defines the overtemperature ΔT trip margin during steady state operation if the temperature, pressure, and f(ΔI) terms are zero.

K_2 is a constant which defines the dependence of the overtemperature ΔT setpoint to T_{avg}.

K_3 is a constant which defines the dependence of the overtemperature ΔT setpoint to pressurizer pressure.

ΔI = $q_t - q_b$, where q_t and q_b are the percent power in the top and bottom halves of the core respectively, and $q_t + q_b$ is total core power in percent of rated power.

f(ΔI) = 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, where q_t and q_b are defined above such that:

(a) for $q_t - q_b$ between -15.75 percent and +6.9 percent, f(ΔI) = 0.

(b) for each percent that the magnitude of $q_t - q_b$ exceeds +6.9 percent, the ΔT trip setpoint shall be automatically reduced by an equivalent of 3.333 percent of rated power.

(c) for each percent that the magnitude of $q_t - q_b$ is more negative than -15.75 percent, the ΔT trip setpoint shall be automatically reduced by an equivalent of 4.000 percent of rated power.

τ_1 = 25 seconds
τ_2 = 3 seconds
S = Laplace Transform Operator, sec^{-1} — A.8.c

T3.3.1-1, #6 (5) Overpower ΔT (A.9)

$$\Delta T \leq \Delta T_o \left(K_4 - K_5 \frac{dTavg}{dt} - K_6(T_{avg} - T')\right)$$

where:

ΔT_o ≤ measured full power ΔT for the channel being calibrated, °F

T_{avg} = measured average temperature for the channel being calibrated, °F (input from instrument racks)

T' = measured full power T_{avg} for the channel being calibrated, °F (can be set no higher than 570.3 °F)

K_4 ≤ ~~1.073~~ 1.154 (L.1)

T3.3.1-1, Note 2

K_5 = 0 for decreasing average temperature

≥ 0.175 sec/°F for increasing average temperature

K_6 = 0 for $T \leq T'$

≥ 0.00134 for $T > T'$

K_4 is a constant which defines the overpower ΔT trip margin during steady state operation if the temperature term is zero.

K_5 is a constant determined by dynamic considerations to compensate for piping delays from the core to the loop temperature detectors; it represents the combination of the equipment static gain setting and the time constant setting.

K_6 is a constant which defines the dependence of the overpower ΔT setpoint to T_{avg}.

$\frac{dTavg}{dt}$ = rate of change of T_{avg}

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

T3.3.1-1, #9 (a) ≥ 90 of normal indicated loop flow — 89% (L.1) (A.13)

T3.3.1-1, #12 (b) Low reactor coolant pump frequency - ≥ 57.2 cps — 57.22 (L.1) (A.14)

T3.3.1-1, #11 (7) Undervoltage - ≥ 70% of normal voltage — 6.9 kV bus — 68.37% (L.1) (A.17) (A.18)

A.1

~~C. Other reactor trips~~

T3.3.1-1, #8 (1) High pressurizer water level - ≤ 92% of span. 97.47% L.1 A.12

T3.3.1-1, #13 (2) Low-low steam generator water level - ≥ 5% of narrow range instrument span. 3.54% L.1 A.19

T3.3.1-1, #15 (3) ~~Anticipatory reactor trip upon~~ turbine trip: Auto Stop Oil Press ≥ 1.6 psig A.21

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

T3.3.1-1, 9 Notes e, g, h ~~A.~~ The reactor trips on low pressurizer pressure, high pressurizer level, low reactor coolant flow for two or more loops, and turbine trip shall be unblocked when:

T3.3.1-1, #17.d ~~(1)~~ ~~Power range nuclear flux ≥ 10% of rated power~~ P-10, ≤ 10% RTP, or A.29

T3.3.1-1, #17.e ~~(2)~~ P-7 input Turbine first stage pressure ~~≥ 10% of equivalent full load~~ ≤ 10% turbine power A.30

T3.3.1-1, Note h The reactor trip on turbine trip may be blocked at power levels ≥10% during turbine overspeed surveillance testing. A.21

T3.3.1-1, #17.c #9 ~~B.~~ The single loop loss of flow reactor trip may be bypassed when the power range nuclear instrumentation indicates ≤ 50% of rated power. The single loop loss-of-flow trip setpoint is hereafter referred to as P-8. A.28

~~**Basis**~~

~~The high flux reactor trip provides redundant protection in the power range for a power excursion beginning from low power. This trip was used in the safety analysis. (1)~~

~~The power range nuclear flux reactor trip high set point protects the reactor core against reactivity excursions which are too rapid to be protected by temperature and pressure protective circuitry. The prescribed set point, with allowance for errors, is consistent with the trip point in the accident analysis. (2) (3)~~

A.1

Add, Function 17.a, P-6 interlock

Add Function 17.b, P-7 interlock

Add Interlock Operability for Functions 17.c, 17.d and 17e

M.10

Amendment No. ~~88~~, 86

A.1

The source and intermediate range reactor trips do not appear in the specification as these settings are not used in the transient and accident analysis (FSAR Section 14). Both trips provide protection during reactor startup. The former is set at about 10^{+5} counts/sec and the latter at a current proportional to approximately 25% of rated full power.

The high and low pressure reactor trips limit the pressure range in which reactor operation is permitted. The high pressurizer pressure reactor trip is backed up by the pressurizer code safety valves for overpressure protection, and is therefore set lower than the set pressure for these valves (2485 psig). The low pressurizer pressure reactor trip also trips the reactor in the unlikely event of a loss of coolant accident. Its setting limit is consistent with the value assumed in the loss of coolant analysis. [4]

The overtemperature Delta-T reactor trip provides core protection against DNB for all combinations of pressure, power, coolant temperature, and axial power distribution, provided only that (1) the transient is slow with respect to piping transit delays from the core to the temperature detectors (about 3.5 seconds) [5], and (2) pressure is within the range between the high and low pressure reactor trips. With normal axial power distribution, the reactor trip limit, with allowance for errors [2], is always below the core safety limit as shown on Figure 2.1-1. If axial peaks are greater than design, as indicated by difference between top and bottom power range nuclear detectors, the reactor trip limit is automatically reduced. [6][7] The values of the constants K_1, K_2, and K_3 are determined during the design of the core for operation with all reactor loops in service. The value for K_1 includes an allowance for instrument channel uncertainty, and therefore is a nominal trip setpoint. K_2 and K_3 are analytical limits, and do not require an allowance for instrument channel uncertainty. The setpoints will ensure that the safety limit of centerline fuel melt will not be reached and the applicable safety limit DNBR will not be violated.

The overpower Delta-T reactor trip prevents power density anywhere in the core from exceeding 118% of design power density, and includes corrections for change in density and heat capacity of water with temperature, and dynamic compensation (via the overall gain in the rate controller) for piping delays from the core to the loop temperature detectors. The specified setpoints meet this requirement. [2] The values of the constants K_4, K_5, and K_6 are determined during the design of the core and the reactor protection system. The value for K_4 includes an allowance for instrument channel uncertainty, and therefore is a nominal trip setpoint. K_5 and K_6 are analytical limits, and do not require an allowance for instrument channel uncertainty.

The overpower limit criteria is that core power be prevented from reaching a value at which fuel pellet centerline melting would occur. Fuel temperature decreases due to cladding creepdown with burnup and consequential reduction of pellet-cladding gap. Thus overpower limits become less restrictive as fuel burnup proceeds.

The T' values represent the measured full power T_{avg} for the overtemperature and overpower Delta-T equations. T' must correspond to the indicated full power T_{avg}, and may only be set as high as 570.3°F if the plant operates at the design full power T_{avg}. Reducing T' for a lower (than design) full power T_{avg} assures that the overtemperature and overpower delta-T setpoint are decreased for any increase in T_{avg} above the indicated loop full power T_{avg}.

A.1

The constants delta-T_o and T' for each overtemperature and overpower protection channel are set in accordance with the measured delta-T and T_{avg} at rated power existing in the loop from which the process inputs for a particular protection channel are supplied. This is done to account for loop to loop differences in delta-T and T_{avg} which may exist as a result of asymmetric steam generator tube plugging.

The low flow reactor trip protects the core against DNB in the event of a loss of one or two reactor coolant pumps. The undervoltage reactor trip protects the core against DNB in the event of a loss of two or more reactor coolant pumps. The set points specified are consistent with the values used in the accident analysis. (8) The low frequency reactor coolant pump trip also protects against a decrease in flow. The specified set point assures a reactor trip signal by opening the reactor coolant pump breaker before the low flow trip point is reached.

The high pressurizer water level reactor trip protects the pressurizer safety valves against water relief. Approximately 1600 ft^3 of water (39.75 ft. above the lower instrument tap) corresponds to 92% of span. The specified set point allows margin for instrument error and transient level overshoot beyond their trip setting so that the trip function prevents the water level from reaching the safety valves.

The low-low steam generator water level reactor trip protects against postulated loss of feedwater accidents. This specified set point assures that there will be sufficient water inventory in the steam generators at the time of trip to allow for starting delays for the Auxiliary Feedwater System (9).

Specified reactor trips are blocked at low power where they are not required for protection and would otherwise interfere with normal plant operations. The prescribed set points at which these trips are unblocked assures their availability in the power range where needed.

Above 10% power, an automatic reactor trip will occur if two reactor coolant pumps are lost during operation. Above the P-8 setpoint for four-loop operation, an automatic reactor trip will occur if any pump is lost. This latter trip will prevent the minimum value of the DNB ratio, DNBR, from going below the applicable safety limit during normal operational transients.

A turbine trip causes a direct reactor trip, when operating at or above 10% power. This anticipatory trip will operate in advance of the pressurizer high pressure reactor trip to reduce the peak Reactor Coolant System pressure. No credit was taken in the accident analyses for operation of this trip. (10)

The steam-feedwater flow mismatch trip does not appear in the specification as this setting is not used in the transient and accident analysis (FSAR Section 14).

References

(1) FSAR 14.1.1

(2) FSAR 14.1.2

(3) FSAR Table 14.1-1

(4) FSAR 14.3.1

(5) FSAR 14.1.2

(6) FSAR 7.2

(7) FSAR 3.2.1

(8) FSAR 14.1.6

(9) FSAR 14.1.9

(10) Generic Letter 82-16, II.K.3.12 (NUREG-0737)

A.1

3.5 INSTRUMENTATION SYSTEMS

Operational Safety Instrumentation

Applicability

Applies to plant instrumentation systems. A.2

Objectives

To provide for automatic initiation of the Engineered Safety Features in the event that principal process variable limits are exceeded, and to delineate the conditions of the plant instrumentation and safety circuits necessary to ensure reactor safety.

Specification

SEE ITS 3.3.2

3.5.1 When the plant is not in the cold shutdown condition, the Engineered Safety Features initiation instrumentation setting limits shall be as stated in Table 3.5-1.

~~3.5.2~~ LCO 3.3.1 3.3.1-1 For instrumentation testing or instrumentation channel failure, plant operation shall be permitted to continue in accordance with Tables 3.5-2 through 3.5-4. A3 to A.30 No more than one channel of a particular protection channel set shall be tested at the same time. A.31 By definition, an instrumentation channel failure shall not be regarded as a channel being tested. L.2

~~3.5.3~~ LCO 3.3.1 Req. Act A.1 In the event the number of in-service channels of a particular function is less than the minimum number of Operable Channels (Col. 3), or the Minimum Degree of Redundancy (Col. 4) cannot be achieved, operation shall be limited according to the requirement shown in Column 5 of Tables 3.5-2 through 3.5-4. L.3

Add Actions Note: Separate Condition entry A.32

Paragraph b of DOCs A.3 to A.30

3.3.1, Req Actions:	~~3.5.4~~	In the event of instrumentation channel failure permitted by specification 3.5.2, the Minimum Degree of Redundancy listed in Tables 3.5-2 through 3.5-4 may be reduced by one, but to not less than zero, and the Minimum Number of Operable Channels listed in these tables may be reduced by one, but not to less than one (except as noted in Table 3.5-3) for a period of 8 hours while instrument channels are tested. The failed channel may be blocked to prevent an unnecessary reactor trip during this time. ~~In the case of three loop operation, the out-of-service channel is permitted to be bypassed during the test period.~~ (A.34) (A.37) (A.33)
Actions Note 2 Note to Req Act D.1.1, E.1, A.1, I.1, K.1		
SEE ITS 3.3.2	3.5.5	The low pressurizer pressure safety injection trip shall be unblocked when the pressurizer pressure is ≥ 2000 psig.
T3.3.1-1, #3 T3.3.1-1, #4	~~3.5.6~~	At least one ~~source range~~ (Mode 3,4,5 – CRD Status) and one intermediate range nuclear instrument channel shall be operable ~~prior to reactor start-up~~. (> P-6 and < P-10 for IR; < P-6 for SR) (M.1) (A.6) (A.7)
SEE ITS 3.3.3	3.5.7	When the reactor is not in the cold shutdown condition, the instrumentation requirements as stated in Table 3.5-5 shall be met.
SEE ITS 3.3.2	3.5.8	A minimum of two channels of containment pressure must be operable when T_{avg} is greater than 350°F.

TSCR 96-124 not shown

SEE ITS 3.3.2

4. The steam line high differential pressure value is well below those differential pressures expected in the event of a large steam line break accident as shown in the safety analysis[3].

5. The high steam line flow measurement ΔP value is approximately 49% of the full steam flow from no load to 20% load. Between 20% and 100% (full) load, the value for the flow measurement ΔP is ramped linearly with respect to first stage turbine pressure from 49% of the full steam flow to 110% of the full steam flow. High steam flow, coincident with low T_{avg} or low steam line pressure, will initiate safety injection in the case of a large steam line break accident. The coincident low T_{avg} value for SIS and steam line isolation initiation is below the hot shutdown value. The coincident steam line pressure value is below the full load operating pressure. The safety analysis shows that these values provide protection in the event of a large steam line break.[3]

~~Instrument Operating Conditions~~

~~During plant operations, the complete instrumentation systems will normally be in service. Reactor safety is provided by the Reactor Protection System, which automatically initiates appropriate action to prevent exceeding established limits. Safety is not compromised, however, by continuing operation with certain instrumentation channels out of service since provisions were made for this in the Plant design. This specification outlines limiting conditions for operation necessary to preserve the effectiveness of the Reactor Control and Protection System when any one or more of the channels are out of service.~~

A.1

Almost all reactor protection channels are supplied with sufficient redundancy to provide the capability for channel calibration and test at power. Exceptions are backup channels such as reactor coolant pump breakers. The removal of one trip channel on process control equipment is accomplished by placing that channel bistable in a tripped mode; e.g., a two-out-of-three circuit becomes a one-out-of-two circuit. A channel bistable may also be placed in a bypassed mode; e.g., a two-out-of-three circuit becomes a two-out-of-two circuit. The nuclear instrumentation system channels are not intentionally placed in a tripped mode since the test signal is superimposed on the normal detector signal to test at power. Testing of the NIS power range channel requires: (a) bypassing the Dropped Rod protection from NIS, for the channel being tested; and (b) defeating the ΔT protection CHANNEL SET that is being fed from the NIS channel and (c) defeating the power mismatch section of T_{avg} control channels when the appropriate NIS channel is being tested. However, the Rod Position System and remaining NIS channels still provide the dropped-rod protection. Testing does not trip the system unless a trip condition exists in a concurrent channel.

In the event that either the specified Minimum Number of Operable Channels or the Minimum Degree of Redundancy cannot be met, the reactor and the remainder of the plant is placed, utilizing normal operating procedures, in that condition consistent with the loss of protection.

The source range and the intermediate range nuclear instrumentation and the turbine and steam-feedwater flow mismatch trip functions are not required to be operable since they were not used in the transient and safety analysis (FSAR Section 14).

The shunt trip features of the reactor trip and bypass breakers were modified as a result of the Salem ATWS events[4]. Operability requirements for the reactor trip breakers and the reactor protection logic relays were added to the reactor protection instrument operating conditions as a result of NRC review of shunt trip modifications at Westinghouse plants[5]. Operability is demonstrated when the logic coincidence relays are tested to show they are capable of initiating a reactor trip. Reactor trip breakers are considered operable when tested to show they are capable of being opened: (a) by the undervoltage device and the shunt trip device independent of each other from an automatic trip signal and (b) from the Control Room Flight Panel manual trip during refueling outages. An exception of 72 hours is allowed before a reactor trip breaker is declared inoperable if only one of the diverse trip features (undervoltage or shunt trip) fails to open the breaker when tested.

A.1

Allowable values contained in these Technical Specifications are determined for the calibration of the complete instrument loop during required calibrations in a refueling cycle. The procedural allowable values for each specific component of the loop have been developed and are included in the applicable calibration or functional test(s). These procedural allowable values have taken into consideration the periodicity of the test and the specific components tested. The allowable value listed in the Technical Specifications can not normally be compared to the results of a specific test due to different calculation methods, but will require an engineering evaluation to determine if the Technical Specification allowable value was exceeded. The number assigned as the Technical Specification allowable value is the worst deviation from the nominal trip setpoint that can occur and still be bounded by setpoint calculations. In all cases the procedural allowable values will be equal to or more restrictive than the allowable values listed in the Technical Specifications.

References:

1) FSAR - Section 7.5
2) FSAR - Section 14.3
3) FSAR - Section 14.2.5
4) GL 83-28 - Item 4.3
5) GL 85-09
6) NYPA Report IP3-RPT-MULT-00763, Revision 1, "24 Month Operating Cycle Technical Specification Operability and Acceptance Criteria."

A.1

LA.1 A.34

TABLE 3.5-2 (Sheet 1 of 3)

REACTOR TRIP INSTRUMENTATION LIMITING OPERATING CONDITIONS

	NO. FUNCTIONAL UNIT	1 NO. OF CHANNELS	2 NO. OF CHANNELS TO TRIP	3 MIN. NUMBER OF OPERABLE CHANNELS	4 MIN. DEGREE OF REDUNDANCY	5 OPERATOR ACTION IF CONDITIONS OF COL. 3 OR 4 CANNOT BE MET*	
T3.3.1-1, #1	1. Manual Reactor Trip	2	1	1	0 (2) (M2)	Maintain hot shutdown (Req. Act B.1, B.2) (M.2) (Req. Act C.1, C.2) (M.3)	A.3
T3.3.1-1, #2.a 2.b	2. Nuclear Flux Power Range	4	2	3	2 (4)	Maintain hot shutdown (Req. Act D.1, D.2) (M.4) (Req. Act E.1, E.2)	A.4 A.5
SEE ITS 3.1.8		4	2	2	1	For zero power physics tests only	SEE ITS 3.1.8
T3.3.1-1, #5	3. Overtemperature ΔT	4	2	3	2 (4)	Maintain hot shutdown (Req. Act E.1, E.2)	A.8
T3.3.1-1, #6	4. Overpower ΔT	4	2	3	2 (4)	Maintain hot shutdown (Req. Act E.1, E.2)	A.9
T3.3.1-1, #7.a	5. Low Pressurizer Pressure	4	2	3	2 (4)	Maintain hot shutdown (Req. Act H.1, H.2)	A.10
T3.3.1-1, #7.b	6. Hi Pressurizer Pressure	3	2	2	1 (3)	Maintain hot shutdown (Req. Act E.1, E.2)	A.11
T3.3.1-1, #8	7. Pressurizer-Hi Water Level	3	2	2	1 (3)	Maintain hot shutdown (Req. Act. H.1, H.2)	A.12
T3.3.1-1, #9	8. Low Flow One Loop (Power ≥ P-8)	3/loop	2/loop (any loop)	2/operable loop	1/operable loop	Maintain hot shutdown (Req. Act H.1, H.2)	A.13
T3.3.1-1, 9.	Low Flow Two Loops (Power < P-8 and ≥ P-10) P-7	3/loop	2/loop (any two loops)	2/operable loop	1/operable loop	Maintain hot shutdown (Req. Act H.1, H.2)	A.14

A.35 (3/loop) A.34

Add ITS 3.3.1, Function 14, SG Level with Flow Mismatch — A20 M9

LA.1 A.34

TABLE 3.5-2 (Sheet 2 of 3)

REACTOR TRIP INSTRUMENTATION LIMITING OPERATING CONDITIONS

	NO. FUNCTIONAL UNIT	1 NO. OF CHANNELS	2 NO. OF CHANNELS TO TRIP	3 MINIMUM OPERABLE CHANNELS	4 MINIMUM DEGREE OF REDUNDANCY	5 OPERATOR ACTION IF CONDITIONS OF COLUMNS 3 OR 4 CANNOT BE MET*	
T3.3.1-1, #13	9. Lo Lo Steam Generator Water Level	3/loop	2/loop	~~2/loop~~	~~1/loop~~ 3/SG	~~Maintain hot shutdown~~ Req Act E.1, E.2	A.19
T3.3.1-1, #11	10. Undervoltage 6.9 KV Bus	1/bus	2	~~3~~	~~2~~ 1/bus	~~Maintain hot shutdown~~ Req Act H.1, H.2	A.17
T3.3.1-1, #12 #10.a #10.b	11. Low Frequency 6.9 KV Bus**	1/bus	~~2~~	~~3~~	~~2~~ 1/RCP 1/bus	~~Maintain hot shutdown~~ Req Act I.1, I.2 Req Act N.1, N.2	A.15 A.16 A.18
T3.3.1-1, #15	12. Turbine Trip: Low auto stop oil pressure	~~3~~	2	~~2~~	~~1~~ 3	Req Act J.1, J.2 Maintain reactor power below 10% of full power	A.21
T3.3.1-1, #18 #19	13. Reactor Trip Breakers***	2	1	~~2~~	~~1~~ 2 trains 1 each/RTB	Req Act L.1, L.2 ~~Maintain hot shutdown****~~ Req Act O.1, O.2	A.23 A.24
T3.3.1-1, #20 #16	14. Reactor Protection Relay Logic	2	1	~~2~~	~~1~~ 2 trains	~~Maintain hot shutdown****~~ Req Act K.1, K.2 Req Act C.1, C.2	A.25 A.22

* Maintain hot shutdown means maintain or ~~proceed to~~ be in hot shutdown ~~within~~ 6 ~~4~~ hours ~~using normal operating procedures~~ or outside Applicable Mode if the unacceptable condition arises during operation. — M.5 A.36

~~** 2/4 trips, all four reactor coolant pumps~~ — LA.1

*** ~~A reactor trip breaker is considered inoperable if any of its components fail to meet test specifications.~~ If either the undervoltage or shunt trip device (not both) prevent a breaker from proper operation, then ~~72~~ 48 hours are allowed to restore the failed device to operable status before the ~~affected breaker is declared inoperable~~ Mode 3 in next 6 hours. — A.1 M.6

Req Act O.1 O.2

Amendment No. 28, 88, 74, 93

ITS 3.3.1

K
L C

TABLE 3.5-2 (Sheet 3 of 3)

Reg. Act C.1, C.2.1, C.2.2

**** Upon proceeding to hot shutdown as a result of an inoperable reactor trip breaker or relay logic, 48 hours are allowed to restore the minimum number of operable channels required by column 3. If minimum operability is not restored after this 48 hours period, rod withdrawal capability shall be defeated within one hour ~~by opening one reactor trip breaker and its associated bypass breaker or isolating power to the Control Rod Drive System.~~ CRD System incapable of Rod withdrawal (A.1) (A.23) (A.25)

ITS 3.3.1

3.11 MOVABLE INCORE INSTRUMENTATION

SEE CTS RELOCATED

Applicability

Applies to the operability of the movable detector instrumentation system.

Objective

To specify functional requirements on the use of the incore instrumentation system, for the recalibration of the excore axial off-set detection system.

Specification

A. A minimum of 2 thimbles per quadrant and sufficient movable incore detectors shall be operable during recalibration of the excore axial off-set detection system.

SR 3.3.1.3, Note 2
SR 3.3.1.6, Note 1

Power shall be limited to 90% of rated power if recalibration requirements for the excore axial off-set detection system, identified in Table 4.1-1, are not met.

C. During the incore/excore calibration procedure, all full core flux maps will be made only when at least 38 of the movable detector guide thimbles are operable.

SEE CTS RELOCATED

Basis

The Movable Incore Instrumentation System[1] has six drives, six detectors, and 58 movable detector guide thimbles in the core. Fifty (50) of these thimbles were provided as part of the original design basis of the plant. The other eight thimbles are supplemental thimbles that were connected during the 8/9 refueling outage. The eight supplemental thimbles are maintained to the same standards as the original 50 thimbles. These eight supplemental thimbles can be used to satisfy the 38 thimble requirement for flux mapping. An appropriate evaluation will be performed prior to the initial use of the supplemental thimbles to satisfy technical specification requirements for flux mapping. The eight supplemental thimbles improve the reliability of the Movable Incore Instrumentation System. Each of the six movable incore detectors can be routed to sixteen or more thimbles. Consequently, the full system has a great deal more capability than would be needed for the calibration of the excore detectors.

To calibrate the excore detectors, it is only necessary that the Movable Incore Instrumentation System be used to determine the gross power distribution in the core as indicated by the power balance between the top and bottom halves of the core.

4 SURVEILLANCE REQUIREMENTS

4.1 OPERATIONAL SAFETY REVIEW

Applicability

Applies to items directly related to safety limits and limiting conditions for operation. Performance of any surveillance test outlined in these specifications is not required if the plant condition is the same as the condition into which the plant would be placed by an unsatisfactory result of that test. Failure to perform a surveillance requirement within the allowed surveillance interval (including extensions specified in definition 1.12), shall constitute noncompliance with the operability requirements of the limiting conditions for operation (LCOs). The time limits for associated action requirements are applicable at the time it is identified that a surveillance requirement has not been performed. Action requirements may be delayed for up to 24 hours to permit completion of the missed surveillance when the allowable outage time limits of the action requirements are less than 24 hours (i.e. for LCOs of less than 24 hours, a 24 hour delay period is permitted before entering the LCO; for LCOs greater than 24 hours, no delay period is permitted).

Objective

To specify the minimum frequency and type of surveillance to be applied to plant equipment and conditions.

Specification

LCO 3.3.1 SR Table Note

~~A.~~ Calibration, testing, and checking of analog channel and testing of logic channel shall be performed as specified in Table 4.1-1 3.3.1-1

A.1

~~B.~~ Sampling and equipment tests shall be conducted as specified in Table 4.1-2 and 4.1-3, respectively.

Basis

A surveillance test is intended to identify conditions in a plant that would lead to a degradation of reactor safety. Should a test reveal such a condition, then the Technical Specifications require that, either immediately or after a specified period of time, the plant be placed in a condition which mitigates or eliminates the consequences of additional related casualties or accidents. If the plant is already in a

It permits an allowable extension of the normal surveillance interval to facilitate surveillance scheduling and consideration of plant operating conditions that may not be suitable for conducting the surveillance; e.g. transient conditions or other ongoing surveillance or maintenance activities. It also provides flexibility to accommodate the length of a fuel cycle for surveillances that are performed at each refueling outage and are specified with an 18-month or 24-month surveillance interval. It is not intended that this provision be used repeatedly as a convenience to extend surveillance intervals beyond that specified for surveillances that are not performed on an 18-month or 24-month basis. Likewise, it is not the intent that 24 month surveillances be performed during power operation unless it is consistent with safe plant operation. The limitation of Definition 1.12 is based on engineering judgement and the recognition that the most probable result of any particular surveillance being performed is the verification of conformance with the Surveillance Requirements. This provision is sufficient to ensure that the reliability ensured through surveillance activities is not significantly degraded beyond that obtained from the specified surveillance interval. The phrase "at least" associated with a surveillance frequency does not negate the 25% extension allowance of Definition 1.12; instead, it permits the performance of more frequent surveillance activities.

Based on experience in operation of both conventional and nuclear plant systems, when the plant is in operation, the minimum checking frequency of once per shift is deemed adequate for reactor and steam system instrumentation.

Calibration

Calibrations are performed to ensure the presentation and acquisition of accurate information.

The nuclear flux (linear level) channels are calibrated daily against a heat balance standard to account for errors induced by changing rod patterns and core physics parameters.

Other channels are subject only to the "drift" errors induced within the instrumentation itself and, consequently, can tolerate longer intervals between calibration. Process system instrumentation errors induced by drift can be expected to remain within acceptable tolerances if recalibration is performed at intervals of 18 or 24 months.

Substantial calibration shifts within a channel (essentially a channel failure) will be revealed during routine checking and testing procedures.

Thus, minimum calibration frequencies of once-per-day for the nuclear flux (linear level) channels, and 18 or 24 months for the process system channels is considered acceptable.

A.1

Testing

The minimum testing frequency for those instrument channels connected to the safety system is based on an average unsafe failure rate of 2.5×10^{-6} failure hrs. per channel. This is based on operating experience at conventional and nuclear plants. An unsafe failure is defined as one which negates channel operability and which, due to its nature, is revealed only when the channel is tested or attempts to respond to a bona fide signal.

For a specified test interval W and an M out of N redundant system with identical and independent channels having a constant failure rate λ, the average availability A is given by:

$$A = \frac{W-Q \quad \left(\frac{W}{N-M+2}\right)}{W} = 1 - \frac{N!}{(N-M+2)!\,(M-1)!}(\lambda W)^{N-M+1}$$

where A is defined as the fraction of time during which the system is functional, and Q is the probability of failure of such a system during a time interval W.

For a 2-out-of-3 system A = 0.9999708, assuming a channel failure rate, λ, equal to 2.5×10^{-6} hr $^{-1}$ and a test interval, W, equal to 2160 hrs.

This average availability of the 2-out-of-3 system is high, hence the test interval of one quarter is acceptable.

Because of their greater degree of redundancy, the 1/3 and 2/4 logic arrays provide an even greater measure of protection and are thereby acceptable for the same testing interval. Those items specified for quarterly testing are associated with process components where other means of verification provide additional assurance that the channel is operable, thereby requiring less frequent testing.

~~Specified surveillance intervals for the Reactor Protection System and Engineered Safety Features have been determined in accordance with WCAP - 10271, Supplement 1, "Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System," and WCAP - 10271, Supplement 2, Revision 1, "Evaluation of Surveillance Frequencies and Out of Service Times for the Engineered Safety Features Actuation System," as approved by the NRC and documented in the SERs (letters to J. J. Sheppard from C. O. Thomas, dated February 21, 1985, and to R. A. Newton from C. E. Rossi, dated February 22, 1989). Surveillance intervals were determined based on maintaining an appropriate level of reliability of the Reactor Protection System and Engineered Safety Features instrumentation.~~

A.1

DELETED

Add SR 3.3.1.11 for NIs

SR 3.3.1.3, Freq — L.5

M.7

Add SR 3.3.1.8 Freq — L.4 — M.4

TABLE 4.1-1 (Sheet 1 of 6)

SR 3.3.1.6 — L.5

MINIMUM FREQUENCIES FOR CHECKS, CALIBRATIONS AND TESTS OF INSTRUMENT CHANNELS

	Channel Description	Check	Calibrate	Test	Remarks	
T3.3.1-1, #2a #2b #5 #6	1. Nuclear Power Range (A.4) SR 3.3.1.2, Notes 1, 2 — SR 3.3.1.3, Notes 1, 2 (A.8) (A.9)	S (12 hours) SR 3.3.1.1	D (1) M (3) SR 3.3.1.2 SR 3.3.1.3 (Add Note)	Q (2) Q (4) SR 3.3.1.7 SR 3.3.1.8	1) Heat balance calibration 2) Bistable action (permissive, rod stop, trips) 3) Upper and lower chambers for axial offset 4) Signal to Δ T — LA2	A.4 A.5 A.8 A.9
T3.3.1-1, #3	2. Nuclear Intermediate Range	S (1) SR 3.3.1.1	N.A. — M.7 SR 3.3.1.11	P (2) SR 3.3.1.8	1) Once/shift when in service 2) Verification of channel response to simulated inputs	A.6
T3.3.1-1, #4	3. Nuclear Source Range	S (1) SR 3.3.1.1	N.A. — M.7 SR 3.3.1.11	P (2) SR 3.3.1.8	1) Once/shift when in service 2) Verification of channel response to simulated inputs	A.7
T3.3.1-1, #5 #6	4. Reactor Coolant Temperature	S ~~## (2)~~ SR 3.3.1.1	24M SR 3.3.1.12	Q (1) SR 3.3.1.7	1) Overtemperature ΔT, overpower ΔT, and low T_{avg} 2) Normal Instrument check interval is once/shift	A.8 A.9
SEE ITS 3.4.2					T_{avg} instrument check interval reduced to every 30 minutes when: - T_{avg}-T_{ref} deviation and low T_{avg} alarms are not reset and, - Control banks are above 0 steps	
T3.3.1-1, #9a 9.b	5. Reactor Coolant Flow	S ## SR 3.3.1.1	24M SR 3.3.1.10	Q SR 3.3.1.7		A.13 A.14
T3.3.1-1 # 8	6. Pressurizer Water Level	S SR 3.3.1.1	24M SR 3.3.1.10	Q SR 3.3.1.7		A.12
T3.3.1-1, 7a 7.b	7. Pressurizer Pressure	S ## SR 3.3.1.1	24M SR 3.3.1.10 SR 3.3.1.12	Q SR 3.3.1.7	High and Low	A.10 A.11 A.8

T3.3.1-1, #5

Amendment No. 38, 65, 74, 93, 107, 123, 126, 137, 140, 149, 150, 168, 170, TSCR 98-043

Overtemp ΔT (A.8)
Overpower ΔT (A.9)

TABLE 4.1-1 (Sheet 2 of 6)

	Channel Description	Check	Calibrate	Test	Remarks	
T3.3.1-1, #11	8. 6.9 KV Voltage	N.A.	18M SR3.3.1.10	Q SR3.3.1.9	Reactor protection circuits only	A.17
T3.3.1-1, #12	6.9 KV Frequency	N.A.	24M SR3.3.1.10	Q	Reactor protection circuits only	A.18
SEE ITS 3.1.7	9. Analog Rod Position	S	24M	M		
T3.3.1-1, #13 #14	10. Steam Generator Level	S SR3.3.1.1	24M SR3.3.1.10	Q SR3.3.1.7		A.19 A.20
SEE ITS 3.3.3	11. Residual Heat Removal Pump Flow	N.A.	24M	N.A.		
	12. Boric Acid Tank Level	S	24M	N.A.	Bubbler tube rodded during calibration	
	13. Refueling Water Storage Tank Level					
	a. Transmitter	W	18M	N.A.	Low level alarm	
	b. Indicating Switch	W	6M	N.A.	Low level alarm	
SEE ITS 3.3.2	14a. Containment Pressure - narrow range	S	24M	Q	High and High-High	
SEE ITS 3.3.3	14b. Containment Pressure - wide range	M	18M	N.A.		
SEE CTS MASTER MARKUP	15. Process and Area Radiation Monitoring:					
	a. Fuel Storage Building Area Radiation Monitor (R-5)	D	24M	Q		
	b. Vapor Containment Process Radiation Monitors (R-11 and R-12)	D	24M	Q		
	c. Vapor Containment High Radiation Monitors (R-25 and R-26)	D	24M	Q		
	d. Wide Range Plant Vent Gas Process Radiation Monitor (R-27)	D	24M	Q		

A.15 A.16

Amendment No. 8, 38, 65, 68, 74, 93, 107, 125, 137, 140, 144, 148, 150, 154, 169

Add SR 3.3.1.11 and SR3.3.1.13 for Functions 17.a (P-6), 17.b (P-7), 17.c (P-8), 17.d (P-10) and 17.e (P-7 input) M.10

TABLE 4.1-1 (Sheet 3 of 6)

	Channel Description	Check	Calibrate	Test	Remarks	
SEE CTS MASTER MARKUP	e. Main Steam Lines Process Radiation Monitors (R-62A, R-62B, R-62C, and R-62D)	D	24M	Q		
	f. Gross Failed Fuel Detectors (R-63A and R-63B)	D	24M	Q		
	16. Containment Water Level Monitoring System:					
	a. Containment Sump	N.A.	24M	N.A.	Narrow Range, Analog	
	b. Recirculation Sump	N.A.	24M	N.A.	Narrow Range, Analog	
	c. Containment Water Level	N.A.	24M	N.A.	Wide Range	
	17. Accumulator Level and Pressure	S	24M	N.A.		
	18. Steam Line Pressure	S	24M	Q		
T3.3.1-1, #17e	19. Turbine First Stage Pressure	S	24M	Q		A.30
T3.3.1-1, #20	20a. Reactor Trip Relay Logic	N.A.	N.A.	TM 3.3.1.5		A.25
SEE 3.3.2	20b. ESF Actuation Relay Logic	N.A.	N.A.	TM		
T3.3.1-1, #15	21. Turbine Trip Low Auto Stop Oil Pressure	N.A.	24M SR 3.3.1.10	N.A.	Add SR 3.3.1.15 M.8	A.21
	~~22. DELETED~~	~~DELETED~~	~~DELETED~~	~~DELETED~~		
SEE CTS MASTER MARKUP	23. Temperature Sensor in Auxiliary Boiler Feedwater Pump Building	N.A.	N.A.	18M		
	24. Temperature Sensors in Primary Auxiliary Building					
	a. Piping Penetration Area	N.A.	N.A.	24M		
	b. Mini-Containment Area	N.A.	N.A.	24M		
	c. Steam Generator Blowdown Heat Exchanger Room	N.A.	N.A.	24M		

ITS 3.3.1

Amendment No. 38, 65, 74, 93, 100, 107, 125, 127, 135, 137, 139, 150, 164, 167, 168, TSCR 98-043

Add T.3.3.1-1, #16 RPS input to ESFAS (A.22)

Add T3.3.1-1, #10a, #10.b RCP Breaker Position (A.15) (A.16)

TABLE 4.1-1 (Sheet 5 of 6)

	Channel Description	Check	Calibrate	Test	Remarks	
SEE ITS 3.3.3	37. Core Exit Thermocouples	D	24M	N.A.		I
SEE ITS 3.4.12	38. Overpressure Protection System (OPS)	D	18M (1)	18M	1) Calibration frequency for OPS sensors (RCS pressure and temperature) is 24 months	
T3.3.1-1, #18 #19	~~39.~~ Reactor Trip Breakers	N.A.	N.A.	TM(1) SR3.3.1.4 24M(2) SR3.3.1.14	~~1) Independent operation of undervoltage and shunt trip attachments~~ ~~2) Independent operation of undervoltage and shunt trip from Control Room manual push-button~~	(A.23) (A.24)
	~~40.~~ Reactor Trip Bypass Breakers	N.A.	N.A.	(1) Note to SR3.3.1.4 24M(2) SR3.3.1.14	~~1) Manual shunt trip prior to each use~~ ~~2) Independent operation of undervoltage and shunt trip from Control Room manual push-button~~	
T3.3.1-1, #1				24M(3) SR 3.3.1.14	~~3) Automatic undervoltage trip~~ (A.15) (A.16)	(A.3)
SEE ITS 3.3.3	41. Reactor Vessel Level Indication System (RVLIS)	D	24M	N.A.		I
SEE ITS 3.6.5	42. Ambient Temperature Sensors Within the Containment Building	D	24M	N.A.		
SEE ITS 3.7.10	43. River Water Temperature # (installed)	S	18M	N.A.	1) Check against installed instrumentation or another portable device	
	44. River Water Temperature # (portable)	S (1)	Q (2)	N.A.	2) Calibrate within 30 days prior to use and quarterly thereafter	
T3.3.1-1, #14	45. Steam Line Flow	S SR3.3.1.1	24M SR3.3.1.10	Q SR3.3.1.7	Engineered Safety Features circuits only	

TABLE 4.1-1 (Sheet 6 of 6)

Table Notation

LA.2

* By means of the movable incore detector system

T3.3.1-1, #2.b ** SR 3.3.1.8, Freq. — Quarterly when reactor power is below the setpoint and prior to each startup if not done previous month (92 days) — A.5 L.4

SEE ITS 3.7.10

*** ~~This surveillance requirement may be extended on a one time basis to no later than April 26, 1997.~~

**** ~~This surveillance requirement may be extended on a one time basis to no later than May 12, 1997.~~

***** ~~This surveillance requirement may be extended on a one time basis to no later than May 14, 1997.~~

TSCR 98-043

\# These requirements are applicable when specification 3.3.F.5 is in effect only.

SEE ITS 3.4.1

\#\# The "each shift" frequency also requires verification that the DNB parameters (Reactor Coolant Temperature, Reactor Coolant Flow, and Pressurizer Pressure) are within the limits of Technical Specification 3.1.H.

T3.3.1-1, #3 #4

S - Each Shift (i.e., at least once per 12 hours)
W - Weekly
P - Prior to each startup if not done previous week — A.6
M - Monthly — A.7
NA - Not Applicable
Q - Quarterly
D - Daily
18M - At least once per 18 months
TM - At least every two months on a staggered test basis (i.e., one train per month)
24M - At least once per 24 months
6M - At least once per 6 months

SEE ITS 1.0

TSCR 98-043

4.5 TESTS FOR ENGINEERED SAFETY FEATURES AND AIR FILTRATION SYSTEMS

A.2

~~Applicability~~

~~Applies to testing of the Safety Injection System, the Containment Spray System, the Hydrogen Recombiner System, and the Air Filtration Systems.~~

~~Objective~~

~~To verify that the subject systems will respond promptly and perform their design functions, if required.~~

Specification

A. SYSTEM TESTS

T 3.3.1-1, #16
SR 3.3.1.4

1. Safety Injection System

A.22

a. System tests shall be performed at least once per 24 months*. With the Reactor Coolant System pressure less than or equal to 350 psig and temperature less than or equal to 350°F, a test safety injection signal will be applied to initiate operation of the system. The safety injection and residual heat removal pumps are made inoperable for this test.

b. The test will be considered satisfactory if control board indication and visual observations indicate that all components have received the safety injection signal in the proper sequence and timing, that is, the appropriate pump breakers shall have opened and closed, and the appropriate valves shall have completed their travel.

SEE ITS 3.5.2

c. Conduct a flow test of the high head safety injection system after any modification is made to either its piping and/or valve arrangement.

d. Verify that the mechanical stops on Valves 856 A, C, D, E, F, H, J and K are set at the position measured and recorded during the most recent ECCS operational flow test or flow tests performed in accordance with (c) above. This surveillance procedure shall be performed following any maintenance on these valves or their associated motor operators and at a convenient outage if the position of the mechanical stops have not been verified in the preceding three months.

* The time delay relays will be tested at intervals no greater than 22.5 months (18 months + 25%).

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.1:
"Reactor Protection System (RPS) Instrumentation"

PART 3:

DISCUSSION OF CHANGES

Differences between CTS and ITS

DISCUSSION OF CHANGES
ITS SECTION 3.3.1 - REACTOR PROTECTION SYSTEM (RPS) INSTRUMENTATION

ADMINISTRATIVE

A.1 In the conversion of the Indian Point Unit 3 Current Technical Specifications (CTS) to the plant specific Improved Technical Specifications (ITS) certain wording preferences or conventions are adopted which do not result in technical changes (either actual or interpretational). Additionally, editorial changes, reformatting, and revised numbering are adopted to make ITS consistent with the conventions in NUREG-1431, Standard Technical Specifications, Westinghouse Plants, Rev. 1, i.e., the improved Standard Technical Specifications.

The CTS Bases are deleted and replaced with comprehensive ITS Bases designed to support interpretation and implementation of the associated Technical Specifications. The Bases explain, clarify, and document the reasons (i.e., bases) for the associated Technical Specifications, and reflect the IP3 plant specific design, analyses, and licensing basis. In accordance with 10 CFR 50.36(a), the ITS Bases are included with the proposed ITS conversion application; however, deletion of the CTS Bases and the adoption of the ITS Bases is an administrative change with no impact on safety.

A.2 CTS Limiting Conditions for Operation (LCOs) and Surveillance Requirements (SRs) include statements of the objective and the applicability. The CTS statements of objective and applicability are deleted because these statements do not establish any requirements and do not provide any guidance for the application of CTS requirements. Therefore, deletion of these statements has no significant adverse impact on safety.

A.3 **ITS 3.3.1, Function 1, Manual Reactor Trip**, is equivalent to CTS Table 3.5-2, Function 1, Manual Reactor Yrip (sic). The ITS conversion modifies the CTS requirements as follows:

a. CTS 3.5 does not specify an Applicability for this Function but CTS Table 3.5-2 establishes an implied Applicability by requiring that the plant be in hot shutdown (Mode 3) if requirements cannot

be met. ITS LCO 3.3.1 requires this function operable in Modes 1 and 2 and in Mode 3, 4 and 5 if the Rod Control System is capable of rod withdrawal and one or more rods are not fully inserted (ITS Table 3.3.1-1, Note a). This is a more restrictive change (see 3.3.1, DOC M.3).

b. CTS Table 3.5-2 requires 1 operable channel with a minimum degree of redundancy of zero. ITS 3.3.1 requires 2 operable channels. This is a more restrictive change (see 3.3.1, DOC M.2). In conjunction with this change, ITS LCO 3.3.1, Required Actions B.1 and C.1, will allow 48 hours to restore an inoperable channel when one of the two channels is inoperable (see 3.3.1, DOC M.3).

c. If requirements for minimum number of channels or minimum level of redundancy are not met (i.e., complete loss of manual reactor trip function), CTS Table 3.5-2 (footnote *) requires that the plant "maintain or proceed to hot shutdown within 4 hours using normal operating procedures." Under the same conditions (i.e., complete loss of manual trip capability), ITS LCO 3.3.1 defaults to ITS LCO 3.0.3 which requires that the plant be placed outside the Applicable Mode in less time than currently permitted by CTS Table 3.5-2 (footnote *). This is a more restrictive change (see 3.3.1, DOC M.5).

d. CTS Table 4.1-1, Item 39 (Remark 2) and Item 40 (Remark 2), require testing of the reactor trip and reactor trip bypass breakers every 24 months. ITS SR 3.3.1.14 maintains this requirement to perform a Trip Actuating Device Operational Test (TADOT) at a Frequency of 24 months. As specified in the Bases for ITS SR 3.3.1.14, this test verifies manual trip capability from the control room.

e. There is no allowable value or setpoint associated with this function.

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated description and justification.

A.4 **ITS 3.3.1, Function 2.a, Power Range Neutron Flux-High (trip)**, is equivalent to CTS 2.3.1.B(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. The ITS conversion modifies the CTS requirements for Power Range Neutron Flux-High as follows:

a. CTS 3.5 does not specify an Applicability for this Function but CTS Table 3.5-2 establishes an implied Applicability of Modes 1 and 2 by requiring that the plant be in hot shutdown (i.e., Mode 3) if requirements cannot be met. ITS requires this function operable in Modes 1 and 2. Therefore, there is no change to the existing Applicability requirement.

b. CTS Table 3.5-2 requires 3 operable channels with a minimum degree of redundancy of 2. This combination creates a requirement for 4 channels with no more than 1 channel in trip and enforces an unstated requirement that an inoperable channel be placed in trip (see ITS 3.3.1, DOC A.34). ITS requires 4 channels and associated Required Actions D.1.1 or D.2.1 will also require that an inoperable channel be placed in trip. Therefore, there is no change to the existing requirements for minimum number of operable channels or minimum degree of redundancy except that the requirements are enforced by the combination of a requirement for a minimum number of channels and a specific requirement to place an inoperable channel in trip.

c. CTS 3.5.4 specifies that the requirements for minimum Operable channels and minimum degree of redundancy be maintained by placing an inoperable channel in trip. No Completion Time is specified but one hour to complete this task is a reasonable interpretation of the exiting requirement. Under the same conditions, ITS LCO 3.3.1, Required Action D.1.1 or D.2.1, allow 6 hours to place the inoperable channel in trip. This is a less restrictive change justified in WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990 (See ITS 3.3.1, DOC L.3).

If requirements for minimum number of channels or minimum level of redundancy are not met, CTS Table 3.5-2 (footnote *) requires that

the plant "maintain or proceed to hot shutdown within 4 hours using normal operating procedures." IP3 interprets this requirement as reactor shutdown must commence within 4 hours and completed (i.e., Mode 3) within the following 4 to 6 hours. Under the same conditions, ITS LCO 3.3.1, Required Action D.3 (if there is a loss of redundancy), or ITS LCO 3.0.3 (if there is a loss of function), allow 6 or 7 hours, respectively, to be in Mode 3. This is a more restrictive change (See ITS 3.3.1, DOC M.5).

When a power range channel is inoperable, the monitoring accuracy Quadrant Power Tilt Ratio (QPTR) is reduced. When in this condition, ITS LCO 3.2.4, Quadrant Power Tilt Ratio (QPTR), requires either a power reduction to ≤ 75% RTP or verification of QPTR at an accelerated Frequency using the incore detectors. ITS LCO 3.3.1, Required Actions D.1.2 and D.2.2, provide a cross reference to and duplicate requirements in ITS SR 3.2.4.1 and/or ITS SR 3.2.4.2. These requirements are consistent with CTS 3.10.2.9. Therefore, the addition of ITS LCO 3.3.1, Required Actions D.1.2 and D.2.2, is an administrative change (See ITS 3.2.4).

CTS 3.5.4 allows a channel to be bypassed for up to 8 hours for testing without taking Actions for an inoperable channel if Function trip capability is maintained. ITS LCO 3.3.1, Note to Required Actions for Condition D, maintains this allowance for surveillance testing and setpoint adjustment of other channels. This testing allowance was justified in WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.

d. CTS Table 4.1-1, Item 1, requires a channel check every shift (12 hours); ITS SR 3.3.1.1 maintains this requirement at the same Frequency by requiring a channel check every 12 hours.

CTS Table 4.1-1, Item 1, requires a heat balance calibration daily; ITS SR 3.3.1.2 maintains this requirement for a heat balance calibration every 24 hours; however, ITS SR 3.3.1.2 includes the acceptance criteria that the NIS channel output must be adjusted if the difference between the NIS channel output and the calorimetric is > 2% RTP. Inclusion of this acceptance

criteria in the ITS is an administrative change with no impact on safety because this acceptance criteria incorporate the current analysis assumptions and procedural requirements. Additionally, ITS SR 3.3.1.2 includes an allowance permitting this SR to be deferred until 24 hours after exceeding 15% RTP which is an explicit recognition that the SR cannot be performed until minimum plant conditions for performing the SR are established. This is an administrative change with no impact on safety because the allowance of 24 hours after exceeding 15% RTP is a reasonable interpretation of the existing requirement and is consistent with current practice.

CTS Table 4.1-1, Item 1, requires a channel test every quarter; ITS SR 3.3.1.7 maintains the requirement to perform a Channel Operation Test (COT) at a Frequency of 92 days.

CTS Table 4.1-1, Item 1, does not include an explicit requirement Channel Calibration of the Power Range Neutron Flux-High although the trip setpoints are verified as part of the quarterly operational test. ITS SR 3.3.1.11 is added to require a Channel Calibration of the Power Range Neutron Flux-High trip function every 24 months. This is a more restrictive change (See ITS 3.3.1, DOC M.7).

Information such as that found in CTS Table 4.1-1, Item 1, Note *, (incore moveable detectors used to perform this test), and information in the remarks column (details about what is included in the test) are relocated to the ITS Bases (see 3.3.1, DOC LA.2).

e. CTS 2.3.1.B(1) establishes the trip setpoint limiting safety system setting (allowable value) for the Power Range Neutron Flux-High at ≤ 109% RTP. This allowable value was established based on Indian Point Nuclear Generating Station Unit No. 3 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, March 1975, and are considered conservative. ITS 3.3.1, Function 2.a, Power Range Neutron Flux-High, will maintain the CTS value as the allowable value.

Each of the changes described above is an administrative change with no

adverse impact on safety except as noted with a cross reference to the associated justification.

A.5 **ITS 3.3.1, Function 2.b, Power Range Neutron Flux-Low (trip),** is equivalent to CTS 2.3.1.A(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 Low. The ITS conversion modifies the CTS requirements for Power Range Neutron Flux-Low as follows:

a. CTS 3.5 does not specify an Applicability for this Function but CTS Table 3.5-2 establishes an implied Applicability by the existence of the P-10 interlock in the plant design as described in the FSAR and by requiring that the plant be in hot shutdown (Mode 3) if requirements cannot be met. ITS requires this function operable in Mode 1 (below the P-10 (Power Range Neutron Flux) interlock) and Mode 2. Therefore, there is no change to the existing Applicability requirement.

b. CTS Table 3.5-2 requires 3 operable channels with a minimum degree of redundancy of 2. This combination creates a requirement for 4 channels with no more than 1 channel in trip and enforces an unstated requirement that an inoperable channel be placed in trip (see ITS 3.3.1, DOC A.34). ITS requires 4 channels and associated Required Action E.1 will also require that an inoperable channel be placed in trip. Therefore, there is no change to the existing requirements for minimum number of operable channels or minimum degree of redundancy except that the requirements are enforced by the combination of a requirement for a minimum number of channels and a specific requirement to place an inoperable channel in trip.

c. CTS 3.5.4 specifies that the requirements for minimum Operable channels and minimum degree of redundancy be maintained by placing an inoperable channel in trip. No Completion Time is specified but one hour to complete this task is a reasonable interpretation of the exiting requirement. Under the same conditions, ITS LCO 3.3.1, Required Action E.1, allows 6 hours to place the inoperable channel in trip. This is a less restrictive change justified in WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990 (See ITS 3.3.1, DOC L.3).

If requirements for minimum number of channels or minimum level of redundancy are not met, CTS Table 3.5-2 (footnote *) requires that the plant "maintain or proceed to hot shutdown within 4 hours using normal operating procedures." IP3 interprets this requirement as reactor shutdown must commence within 4 hours and completed (i.e., Mode 3) within the following 4 to 6 hours. Under the same conditions, ITS LCO 3.3.1, Required Action E.2 (if there is a loss of redundancy), or ITS LCO 3.0.3 (if there is a loss of function), allow 6 or 7 hours, respectively, to be in Mode 3. This is a more restrictive change (See ITS 3.3.1, DOC M.5).

CTS 3.5.4 allows a channel to be bypassed for up to 8 hours for testing without taking Actions for an inoperable channel if Function trip capability is maintained. ITS LCO 3.3.1, Note to Required Actions for Condition E, maintains this allowance for surveillance testing and setpoint adjustment of other channels. This testing allowance was justified in WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.

d. CTS Table 4.1-1, Item 1, requires a channel check every shift (12 hours); ITS SR 3.3.1.1 maintains this requirement at the same Frequency by requiring a channel check every 12 hours.

CTS Table 4.1-1, Item 1, requires a channel test every quarter with associated Note ** to Table 4.1-1 requiring this test to be performed not less than 30 days prior to a reactor startup. ITS SR 3.3.1.8 maintains the requirement to perform a COT prior to reactor startup but only if the SR has not been performed in the previous 92 days. This is a less restrictive change (see 3.3.1, DOC L.4).

CTS Table 4.1-1, Item 1, requires a channel test every quarter with associated Note ** to Table 4.1-1 requiring this test to be performed when below the setpoint (i.e., P-10 setpoint). ITS SR 3.3.1.8 maintains the requirement to perform a COT quarterly when below the P-10 setpoint; however, the ITS SR 3.3.1.8 Frequency allows the SR to be deferred for 16 hours after power is reduced below P-10. This note is an explicit recognition that the SR cannot be performed until minimum plant conditions for performing

the SR are established. This is an administrative change with no impact on safety because allowing 16 hours after plant conditions are established is a reasonable interpretation of the existing Note ** to Table 4.1-1 which requires that the SR be performed quarterly when below the P-10 setpoint.

CTS Table 4.1-1, Item 1, does not include an explicit requirement Channel Calibration of the Power Range Neutron Flux-Low although the trip setpoints are verified as part of the quarterly operational test. ITS SR 3.3.1.11 is added to require a Channel Calibration of the Power Range Neutron Flux-Low trip function every 24 months. This is a more restrictive change (See ITS 3.3.1, DOC M.7).

Information such as that found in CTS Table 4.1-1, Item 1, Note *, (incore moveable detectors used to perform this test), and information in the remarks column (details about what is included in the test) are relocated to the ITS Bases (see 3.3.1, DOC LA.2).

e. CTS 2.3.1.A(1) establishes the trip setpoint limiting safety system setting (allowable value) for the Power Range Neutron Flux-Low at ≤ 25% RTP. This allowable value was established based on Indian Point Nuclear Generating Station Unit No. 3 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, March 1975, and are considered conservative. ITS 3.3.1, Function 2.b, Power Range Neutron Flux-Low, will maintain the CTS value as the allowable value.

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated justification.

A.6 **ITS 3.3.1, Function 3, Intermediate Range Neutron Flux (trip)**, is not identified as a safety limit or limiting condition of operation in the CTS because IRM trip Function is assumed to be a backup to Power Range Neutron Flux-Low trip in the transient and accident analysis (FSAR Section 14).

a. ITS 3.3.1, Function 3, IRM Flux (trip), is required to be Operable in Mode 1 below the P-10 setpoint, and in MODE 2, when there is a potential for an uncontrolled RCCA bank rod withdrawal accident during reactor startup. Above the P-10 setpoint, the Power Range Neutron Flux-High Setpoint trip provides core protection for a rod withdrawal accident. In MODE 3, 4, or 5, the Intermediate Range Neutron Flux trip does not have to be OPERABLE because the control rods must be fully inserted and only the shutdown rods may be withdrawn (except during rod testing).

b. ITS 3.3.1, Function 3, will require one channel of the IRM trip function. This requirement is added to the ITS because it provides redundant protection to the Power Range Neutron Flux-Low Setpoint trip Function for an uncontrolled RCCA bank rod withdrawal accident from a subcritical condition during startup.(see 3.3.1, DOC M.1). Additionally, the control room indication implicit in the requirement for this Function provides the monitoring requirements currently established in CTS 3.5.6 (see ITS 3.3.1, DOC M.1).

c. In conjunction with this change, ITS LCO 3.3.1, Required Actions F.1 and F.2, are added to require suspending operations involving positive reactivity addition immediately and reducing power to outside the Applicable Mode within 2 hours if the one required channel of Intermediate Range Neutron Flux (trip) is not Operable.

d. CTS Table 4.1-1, Item 2, requires a channel check of the IRM output every shift; ITS SR 3.3.1.1 maintains this requirement at the same Frequency by requiring a channel check every 12 hours.

CTS Table 4.1-1, Item 2 (Frequency P(2)), requires that IRM response to a simulated signal (i.e., Channel Operational Test) be performed "prior to each startup if not performed in the previous week." ITS SR 3.3.1.8 maintains the requirement to perform a COT; however, the Frequency is extended to 92 days (See ITS 3.3.1, DOC L.4).

CTS Table 4.1-1, Item 2, does not include an explicit requirement to perform a COT of the IRM Flux (trip) during a reactor shutdown.

This is an implicit assumption that the reactor shutdown will always be completed and the plant will not spend a significant amount of time in the Applicable Mode for this function. ITS SR 3.3.1.8 includes a new requirement to perform a COT for ITS 3.3.1, Function 3, within 16 hours after reducing power below the P-10 setpoint (See ITS 3.3.1, DOC M.4). This ensures that the COT will verify function Operability if the plant expects to stay critical, while allowing this SR to be skipped if the reactor shutdown will be completed promptly.

CTS Table 4.1-1, Item 2, does not include an explicit requirement Channel Calibration of the IRM Flux (trip) although the trip setpoints are verified as part of the operational test. ITS SR 3.3.1.11 is added to require a Channel Calibration of the Intermediate Range Neutron Flux trip function every 24 months. This is a more restrictive change (See ITS 3.3.1, DOC M.7).

e. CTS 2.3 does not establish a limiting safety system setting (allowable value) for the IRM Flux (trip) function although the CTS Bases indicate that the setpoint is equivalent to approximately 25% RTP. 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 the ITS Bases and is maintained at 25% RTP. This allowable value was established based on Indian Point Nuclear Generating Station Unit No. 3 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, March 1975.

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated description and justification.

A.7 **ITS 3.3.1, Function 4, Source Range Neutron (SRM) Flux (trip)**, is not identified as a safety limit or limiting condition of operation in the CTS because SRM trip Function is assumed to be a backup to Power Range

Neutron Flux-Low trip in the transient and accident analysis (FSAR Section 14).

a. ITS 3.3.1, Function 4, SRM Flux (trip), is required to be Operable in Mode 2 below the P-6 (IRM interlock) setpoint, and in Modes 3, 4 and 5 when the rod control system is capable of rod withdrawal or any rod is not fully inserted. The NIS source range detectors do not provide any inputs to control systems. The source range trip is the only RPS automatic protection function required in MODES 3, 4, and 5. Therefore, the functional capability at the specified Trip Setpoint is assumed to be available.

b. ITS 3.3.1, Function 4, SRM Flux (trip), will require one channel of the SRM trip function. This requirement is added to the ITS because it provides redundant protection to the Power Range Neutron Flux-Low Setpoint trip Function for an uncontrolled RCCA bank rod withdrawal accident from a subcritical condition during startup.(see 3.3.1, DOC M.1). One channel is acceptable because administrative controls also prevent the uncontrolled withdrawal of rods.

C. In conjunction with this change, ITS LCO 3.3.1, Required Action G.1. is added to require opening the Reactor Trip Breakers (RTBs) immediately if the one required channel of SRM Neutron Flux (trip) is not Operable. This Action places the plant outside the Applicable Mode.

d. CTS Table 4.1-1, Item 3, requires a channel check of the SRM output every shift; ITS SR 3.3.1.1 maintains this requirement at the same Frequency by requiring a channel check every 12 hours.

CTS Table 4.1-1, Item 3 (Frequency P(2)), requires that SRM response to a simulated signal (i.e., Channel Operational Test) be performed "prior to each startup if not performed in the previous week." ITS SR 3.3.1.8 maintains the requirement to perform a COT; however, the Frequency is extended to 92 days (See ITS 3.3.1, DOC L.4).

CTS Table 4.1-1, Item 3, does not include an explicit requirement

to perform a COT of the SRM Flux (trip) during a reactor shutdown. This is an implicit assumption that the reactor shutdown will always be completed and the plant will not spend a significant amount of time in the Applicable Mode for this function.

i. When in Mode 2, ITS SR 3.3.1.8 establishes a new requirement to perform a COT for ITS 3.3.1, Function 4, within 8 hours after reducing power below the P-6 (IRM Flux interlock) setpoint. This ensures that the COT will verify function Operability if the plant expects to stay critical, while allowing this SR to be skipped if the reactor shutdown will be completed promptly (See ITS 3.3.1, DOC M.4).

ii. When in Modes 3, 4 or 5 with CRD system capable of rod withdrawal and one or more rods not fully inserted, ITS SR 3.3.1.7 establishes a new requirement to perform a COT for ITS 3.3.1, Function 4, within 8 hours after entering Mode 3 from Mode 2 and every 92 days thereafter. This change is needed because the source range trip is the only RPS automatic protection function required in MODES 3, 4, and 5 (See ITS 3.3.1, DOC M.4).

CTS Table 4.1-1, Item 3, does not include an explicit requirement Channel Calibration of the SRM Flux (trip) although the trip setpoints are verified as part of the operational test. ITS SR 3.3.1.11 is added to require a Channel Calibration of the Source Range Neutron Flux trip function every 24 months. This is a more restrictive change (See ITS 3.3.1, DOC M.7).

e. CTS 2.3 does not establish a limiting safety system setting (allowable value) for the SRM Flux (trip) function although the CTS Bases indicate that the setpoint is equivalent to approximately 1.0 E+5 counts per second.

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 is maintained in the ITS Bases and is maintained at 1.0 E+5 counts per second. This allowable value was established based on Indian Point Nuclear Generating Station Unit No. 3 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, March 1975, (Ref. 8).

A.8 **ITS 3.3.1, Function 5, Overtemperature delta T**, is equivalent to CTS 2.3.1.B(4) and CTS Table 3.5-2, Function 3, Overtemperature delta T. The ITS conversion modifies the CTS requirements for Overtemperature delta T as follows:

a. CTS 3.5 does not specify an Applicability for this Function but CTS Table 3.5-2 establishes an implied Applicability of Modes 1 and 2 by requiring that the plant be in hot shutdown (i.e., Mode 3) if requirements cannot be met. ITS requires this function operable in Modes 1 and 2. Therefore, there is no change to the existing Applicability requirement.

b. CTS Table 3.5-2 requires 3 operable channels with a minimum degree of redundancy of 2. This combination creates a requirement for 4 channels with no more than 1 channel in trip and enforces an unstated requirement that an inoperable channel be placed in trip (see ITS 3.3.1, DOC A.34). ITS requires 4 channels and associated Required Action E.1 will also require that an inoperable channel be placed in trip. Therefore, there is no change to the existing requirements for minimum number of operable channels or minimum degree of redundancy except that the requirements are enforced by the combination of a requirement for a minimum number of channels and a specific requirement to place an inoperable channel in trip.

c. CTS 3.5.4 specifies that the requirements for minimum Operable channels and minimum degree of redundancy be maintained by placing an inoperable channel in trip. No Completion Time is specified but one hour to complete this task is a reasonable interpretation of the exiting requirement. Under the same conditions, ITS LCO 3.3.1, Required Action E.1, allows 6 hours to place the inoperable channel in trip. This is a less restrictive change justified in

WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990 (See ITS 3.3.1, DOC L.3).

If requirements for minimum number of channels or minimum level of redundancy are not met, CTS Table 3.5-2 (footnote *) requires that the plant "maintain or proceed to hot shutdown within 4 hours using normal operating procedures." IP3 interprets this requirement as reactor shutdown must commence within 4 hours and completed (i.e., Mode 3) within the following 4 to 6 hours. Under the same conditions, ITS LCO 3.3.1, Required Action E.2 (if there is a loss of redundancy), or ITS LCO 3.0.3 (if there is a loss of function), allow 6 or 7 hours, respectively, to be in Mode 3. This is a more restrictive change (See ITS 3.3.1, DOC M.5).

CTS 3.5.4 allows a channel to be bypassed for up to 8 hours for testing without taking Actions for an inoperable channel if Function trip capability is maintained. ITS LCO 3.3.1, Note to Required Actions for Condition E, maintains this allowance for surveillance testing and setpoint adjustment of other channels. This testing allowance was justified in WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.

d. CTS Table 4.1-1, Item 1 (Remark 4), Item 4, and Item 7, require channel checks every shift of the inputs to Overtemperature delta T (i.e., Nuclear Power Range, RCS Temperature, and RCS Pressure); ITS SR 3.3.1.1 maintains this requirement at the same Frequency by requiring a channel check of each of the various inputs to this Function every 12 hours.

CTS Table 4.1-1, Item 1 (Remark 3 with Note *), requires that the monthly calibration of the power range channels that consists of a comparison of the upper and lower axial offset using the incore detectors. ITS SR 3.3.1.3 maintains the requirement to compare results of the incore detector measurements to NIS AFD with the following differences:

i. The Frequency of ITS SR 3.3.1.3 is extended from once per month to every 31 effective full power days (EFPD) (see ITS 3.3.1, DOC L.5).

ii. ITS SR 3.3.1.3, Note 1, includes acceptance criteria that the NIS channel must be adjusted if absolute difference is ≥ 3%. 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.

iii. ITS SR 3.3.1.3, Note 2, incorporates the allowance in CTS 3.11.B that this SR is required to be performed only when Thermal Power is > 90% RTP. This Note maintains the CTS recognition that the potential for exceeding Axial Flux Difference is very small when Thermal Power is < 90% RTP. Additionally, this is an explicit recognition that the SR cannot be performed until minimum plant conditions for performing the SR are established.

CTS Table 4.1-1, Item 1 (Remark 4), Item 4, and Item 7, require a channel test every quarter; ITS SR 3.3.1.7 maintains the requirement to perform a Channel Operation Test (COT) at a Frequency of 92 days.

CTS Table 4.1-1, Item 4 and 7, require a calibration of 2 of the 3 inputs to Overtemperature delta T every 24 months. CTS Table 4.1-1, Item 1, does not include an explicit requirement 24 month Channel Calibration of the Power Range Neutron Flux-High although the trip setpoints are verified as part of the quarterly operational test. ITS SR 3.3.1.11 is added to require a Channel Calibration of the Power Range Neutron Flux-High trip function every 24 months (See ITS 3.3.1, DOC M.7). This calibration supports the NI input to the the Overtemperature delta T function. ITS SR 3.3.1.12 maintains the CTS requirement for calibration of the Overtemperature delta T function at the same Frequency by requiring a Channel Calibration every 24 months.

Information such as that found in CTS Table 4.1-1, Item 1, Note *, (incore moveable detectors used to perform this test), and information in the remarks column (details about what is included in the test) are relocated to the ITS Bases (see 3.3.1, DOC LA.2).

e. CTS 2.3.1.B(4) establishes the trip setpoint limiting safety system setting (allowable value) 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). ITS 3.3.1, Function 5 (and associated acceptance criteria in Note 1), uses the same inputs, equation and constants used in the CTS with the following differences:

i. CTS trip setpoint limiting safety system setting (allowable value) are based on the Indian Point Nuclear Generating Station Unit No. 3 Plant Manual, Volume VI: Precautions, Limitations, and Setpoints, March 1975. ITS will use allowable values calculated in accordance with Engineering Standards Manual IES-3 and IES 3-B, Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3). (See ITS 3.3.1, DOC L.1)

ii. 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.

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated description and justification.

A.9 **ITS 3.3.1, Function 6, Overpower delta T**, is equivalent to CTS 2.3.1.B(5) and CTS Table 3.5-2, Function 4, Overpower delta T. The ITS conversion modifies the CTS requirements for Overpower delta T as follows:

a. CTS 3.5 does not specify an Applicability for this Function but CTS Table 3.5-2 establishes an implied Applicability of Modes 1

and 2 by requiring that the plant be in hot shutdown (i.e., Mode 3) if requirements cannot be met. ITS requires this function operable in Modes 1 and 2. Therefore, there is no change to the existing Applicability requirement.

b. Changes to requirements for minimum number of Operable channels for CTS Table 3.5-2, Function 4, Overpower delta T, are identical to the changes to CTS Table 3.5-2, Function 3, Overtemperature delta T. (See ITS 3.3.1, DOC A.8.b and DOC A.34).

c. Changes to the Required Actions and Completion Times for CTS Table 3.5-2,Function 4, Overpower delta T, as implemented in ITS 3.3.1, Function 6,Overpower delta T, are identical to the changes for CTS Table 3.5-2, Function 3, Overtemperature delta T, as implemented by ITS 3.3.1, Function 3, Overtemperature delta T. (See ITS 3.3.1, DOC A.10.c, DOC L.3, DOC M.5).

d. CTS Table 4.1-1, Item 1 (Remark 4), and Item 4, require channel checks every shift of the inputs to Overpower delta T (i.e., Nuclear Power Range and RCS Temperature): ITS SR 3.3.1.1 maintains this requirement at the same Frequency by requiring a channel check of each of the various inputs to this Function every 12 hours.

CTS Table 4.1-1, Item 4, requires a channel test every quarter; ITS SR 3.3.1.7 maintains the requirement to perform a Channel Operation Test (COT) at a Frequency of 92 days.

CTS Table 4.1-1,Item 4 requires a calibration of RCS Temperature input to the Overpower delta T every 24 months. CTS Table 4.1-1, Item 1, does not include an explicit requirement 24 month Channel Calibration of the Power Range Neutron Flux-High although the trip setpoints are verified as part of the operational test. ITS SR 3.3.1.11 is added to require a Channel Calibration of the Power Range Neutron Flux-High trip function every 24 months (See ITS 3.3.1, DOC M.7). This calibration supports the NI input to the the Overpower delta T function. ITS SR 3.3.1.12 maintains the CTS requirement for calibration of the Overpower delta T function at the same Frequency by requiring a Channel Calibration every 24

months.

Information such as that found in CTS Table 4.1-1, Item 1, Note *, (incore moveable detectors used to perform this test), and information in the remarks column (details about what is included in the test) are relocated to the ITS Bases (see 3.3.1, DOC LA.2).

e. CTS 2.3.1.B(5) establishes the trip setpoint limiting safety system setting (allowable value) for the Overpower delta T function based a calculation that includes input from various parameters as described in CTS 2.3.1.B(5). ITS 3.3.1, Function 6 (and associated acceptance criteria in Note 2), uses the same inputs, equation and constants used in the CTS with the following differences:

i. CTS trip setpoint limiting safety system setting (allowable value) are based on the Indian Point Nuclear Generating Station Unit No. 3 Plant Manual, Volume VI: Precautions, Limitations, and Setpoints, March 1975. ITS will use allowable values calculated in accordance with Engineering Standards Manual IES-3 and IES 3-B, Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3). (See ITS 3.3.1, DOC L.1)

ii. ITS 3.3.1, Function 6, acceptance criteria in Note 2 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.

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated description and justification.

A.10 **ITS 3.3.1, Function 7.a, Pressurizer Pressure-Low,** is equivalent to CTS 2.3.1.B(3) and CTS Table 3.5-2, Function 5, Low Pressurizer Pressure. The ITS conversion modifies the CTS requirements for Pressurizer Pressure-Low as follows:

a. CTS 2.3.2.A specifies that this Function shall be unblocked when (1) Power range nuclear flux ≥ 10% of rate power, or (2) Turbine first stage pressure ≥ 10% of equivalent full load (i.e., Function must be automatically unblocked above the P-7 interlock). ITS 3.3.1, Function 7.a, requires this function operable in Mode 1 and associated Note (e) specifies that this Function is required only when above the P-7 (Low Power Reactor Trip Block) interlock. Therefore, there is no change to the Applicability of this Function.

b. CTS Table 3.5-2 requires 3 operable channels with a minimum degree of redundancy of 2. This combination creates a requirement for 4 channels with no more than 1 channel in trip and enforces an unstated requirement that an inoperable channel be placed in trip (see ITS 3.3.1, DOC A.34). ITS requires 4 channels and associated Required Action H.1 will also require that an inoperable channel be placed in trip. Therefore, there is no change to the existing requirements for minimum number of operable channels or minimum degree of redundancy except that the requirements are enforced by the combination of a requirement for a minimum number of channels and a specific requirement to place an inoperable channel in trip.

c. CTS 3.5.4 specifies that the requirements for minimum Operable channels and minimum degree of redundancy be maintained by placing an inoperable channel in trip. No Completion Time is specified but one hour to complete this task is a reasonable interpretation of the exiting requirement. Under the same conditions, ITS LCO 3.3.1, Required Action H.1, allows 6 hours to place the inoperable channel in trip. This is a less restrictive change justified in WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990 (See ITS 3.3.1, DOC L.3).

If requirements for minimum number of channels or minimum level of

redundancy are not met, CTS Table 3.5-2 (footnote *) requires that the plant "maintain or proceed to hot shutdown within 4 hours using normal operating procedures." IP3 interprets this requirement as reactor shutdown must commence within 4 hours and completed (i.e., Mode 3) within the following 4 to 6 hours.

Under the same conditions, ITS LCO 3.3.1, Required Action H.2 (if there is a loss of redundancy), or ITS LCO 3.0.3 (if there is a loss of function), allow 6 or 7 hours, respectively, to reduce power less < P-7 setpoint (i.e., place the plant outside the Applicability for the Function). The requirement to place the plant outside of the Applicable Mode versus Mode 3 is an administrative change because it is a reasonable interpretation of the equivalent CTS requirement. The reduction in the Completion Time (elimination of the 4 hour delay until shutdown is started) is a more restrictive change (See ITS 3.3.1, DOC M.5).

CTS 3.5.4 allows a channel to be bypassed for up to 8 hours for testing without taking Actions for an inoperable channel if Function trip capability is maintained. ITS LCO 3.3.1, Note to Required Actions for Condition H, maintains this allowance for surveillance testing and setpoint adjustment of other channels. This testing allowance was justified in WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.

d. CTS Table 4.1-1, Item 7, requires a channel check every shift; ITS SR 3.3.1.1 maintains this requirement at the same Frequency by requiring a channel check every 12 hours.

CTS Table 4.1-1, Item 7, requires a channel test every quarter; ITS SR 3.3.1.7 maintains the requirement to perform a Channel Operation Test (COT) at a Frequency of 92 days.

CTS Table 4.1-1, Item 7, requires a channel calibration every 24 months; ITS SR 3.3.1.10 maintains the requirement to perform a Channel Calibration at a Frequency of 24 months.

e. CTS 2.3.1.B(3) establishes the trip setpoint limiting safety system setting (allowable value) for the for the Pressurizer

Pressure-Low at ≥1800 psig. This LSSS is based on the Indian Point Nuclear Generating Station Unit No. 3 Plant Manual, Volume VI: Precautions, Limitations, and Setpoints, March 1975. ITS 3.3.1, Function 7.a, Pressurizer Pressure-Low, establishes the allowable value at ≥ 1749 psig because ITS uses allowable values calculated in accordance with Engineering Standards Manual IES-3 and IES 3-B, Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3) (See ITS 3.3.1, DOC L.1).

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated description and justification.

A.11 **ITS 3.3.1, Function 7.b, Pressurizer Pressure-High**, is equivalent to CTS 2.3.1.B(2) and CTS Table 3.5-2, Function 6, Hi Pressurizer Pressure. The ITS conversion modifies the CTS requirements for Pressurizer Pressure-High as follows:

a. CTS 3.5 does not specify an Applicability for this Function but CTS Table 3.5-2 establishes an implied Applicability of Modes 1 and 2 by requiring that the plant be in hot shutdown (i.e., Mode 3) if requirements cannot be met. ITS requires this function operable in Modes 1 and 2. Therefore, there is no change to the existing Applicability requirement.

b. CTS Table 3.5-2 requires 2 operable channels with a minimum degree of redundancy of 1. This combination creates a requirement for 3 channels with no more than 1 channel in trip and enforces an unstated requirement that an inoperable channel be placed in trip (see 3.3.1, DOC A.34). ITS requires 3 channels and associated Required Action E.1 will also require that an inoperable channel be placed in trip. Therefore, there is no change to the existing requirements for minimum number of operable channels or minimum degree of redundancy except that the requirements are enforced by the combination of a requirement for a minimum number of channels and a specific requirement to place an inoperable channel in trip.

c. CTS 3.5.4 specifies that the requirements for minimum Operable

channels and minimum degree of redundancy be maintained by placing an inoperable channel in trip. No Completion Time is specified but one hour to complete this task is a reasonable interpretation of the exiting requirement. Under the same conditions, ITS LCO 3.3.1, Required Action E.1, allows 6 hours to place the inoperable channel in trip. This is a less restrictive change justified in WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990 (See ITS 3.3.1, DOC L.3).

If requirements for minimum number of channels or minimum level of redundancy are not met, CTS Table 3.5-2 (footnote *) requires that the plant "maintain or proceed to hot shutdown within 4 hours using normal operating procedures." IP3 interprets this requirement as reactor shutdown must commence within 4 hours and completed (i.e., Mode 3) within the following 4 to 6 hours. Under the same conditions, ITS LCO 3.3.1, Required Action E.2 (if there is a loss of redundancy), or ITS LCO 3.0.3 (if there is a loss of function), allow 6 or 7 hours, respectively, to be in Mode 3. This is a more restrictive change (See ITS 3.3.1, DOC M.5).

CTS 3.5.4 allows a channel to be bypassed for up to 8 hours for testing without taking Actions for an inoperable channel if Function trip capability is maintained. ITS LCO 3.3.1, Note to Required Actions for Condition E, maintains this allowance for surveillance testing and setpoint adjustment of other channels. This testing allowance was justified in WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.

d. Changes to Surveillance requirements CTS Table 4.1-1, Item 7, Pressurizer Pressure, for ITS 3.3.1, Function 7.b, Pressurizer Pressure-High, are identical to the changes to CTS Table 4.1-1, Item 7, for ITS 3.3.1, Function 7.a, Pressurizer Pressure-Low.

e. CTS 2.3.1.B(2) establishes the trip setpoint limiting safety system setting (allowable value) for the for the Pressurizer Pressure-High at ≤ 2385 psig. This LSSS is based on the Indian Point Nuclear Generating Station Unit No. 3 Plant Manual, Volume VI: Precautions, Limitations, and Setpoints, March 1975. ITS 3.3.1, Function 7.b, Pressurizer Pressure-High, establishes the

allowable value at ≤ 2408.24 psig because ITS uses allowable values calculated in accordance with Engineering Standards Manual IES-3 and IES 3-B, Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3) (See ITS 3.3.1, DOC L.1).

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated description and justification.

A.12 **ITS 3.3.1, Function 8, Pressurizer Water Level-High**, is equivalent to CTS 2.3.1.C(1) and CTS Table 3.5-2, Function 7, Pressurizer-Hi Water Level. The ITS conversion modifies the CTS requirements for Pressurizer Pressure-Low as follows:

a. CTS 2.3.2.A specifies that this Function shall be unblocked when (1) Power range nuclear flux ≥ 10% of rate power, or (2) Turbine first stage pressure ≥ 10% of equivalent full load. This means that the Function must be automatically unblocked above the P-7 interlock setpoint. ITS requires this function operable in Mode 1 and associated Note (e) specifies that this Function is required only when above the P-7 (Low Power Reactor Trip Block) interlock. Therefore, there is no change to the Applicability of this Function.

b. CTS Table 3.5-2 requires 2 operable channels with a minimum degree of redundancy of 1. This combination creates a requirement for 3 channels with no more than 1 channel in trip and enforces an unstated requirement that an inoperable channel be placed in trip (see 3.3.1, DOC A.34). ITS requires 3 channels and associated Required Action H.1 will also require that an inoperable channel be placed in trip. Therefore, there is no change to the existing requirements for minimum number of operable channels or minimum degree of redundancy except that the requirements are enforced by the combination of a requirement for a minimum number of channels and a specific requirement to place an inoperable channel in trip.

c. Changes to the Required Actions and Completion Times for CTS Table

3.5-2, Function 7, Pressurizer-Hi Water Level as implemented in ITS 3.3.1, Function 8, Pressurizer Water Level-High, are identical to the changes for CTS Table 3.5-2, Function 5, Low Pressurizer Pressure, as implemented by ITS 3.3.1, Function 7.a, Pressurizer Pressure-Low. (See ITS 3.3.1, DOC A.10.c, DOC L.3, DOC M.5).

d. CTS Table 4.1-1, Item 6, Pressurizer Water level, requires a channel check every shift; ITS SR 3.3.1.1 maintains this requirement at the same Frequency by requiring a channel check every 12 hours.

CTS Table 4.1-1, Item 6, requires a channel test every quarter; ITS SR 3.3.1.7 maintains the requirement to perform a Channel Operation Test (COT) at a Frequency of 92 days.

CTS Table 4.1-1, Item 6, requires a channel calibration every 24 months; ITS SR 3.3.1.10 maintains the requirement to perform a Channel Calibration at a Frequency of 24 months.

e. CTS 2.3.1.C(1) establishes the trip setpoint limiting safety system setting (allowable value) for the for the Pressurizer-Hi Water Level at ≤ 92% of span. This LSSS is based on the Indian Point Nuclear Generating Station Unit No. 3 Plant Manual, Volume VI: Precautions, Limitations, and Setpoints, March 1975. ITS 3.3.1, Function 8, Pressurizer Water Level-High, establishes the allowable value at 97.47% of span because ITS uses allowable values calculated in accordance with Engineering Standards Manual IES-3 and IES 3-B, Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3) (See ITS 3.3.1, DOC L.1).

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated description and justification.

A.13 **ITS 3.3.1, Function 9, Reactor Coolant Flow-Low (trip) (One Loop),** replaces the following two CTS Functions:

a. CTS Table 3.5-2, Function 8(a), Low Flow One Loop (Power ≥ P-8); and,

b. CTS Table 3.5-2, Function 8(b), Low Flow Two Loops (Power < P-8 and ≥ P-10[1]).

The ITS specifies that there is one Reactor Coolant Flow-Low trip and that this trip function is modified by plant conditions as follows:

a. Trip occurs on loss of flow in one loop if ≥ P-8 (i.e., 50% RTP);
b. Trip does not occur until there is a loss of flow in two loops if RTP is < P-8; and,
c. Trip does not occur on a loss of flow if < P-7 (CTS P-10) (i.e., 10% RTP).

The ITS conversion modifies the CTS requirements for Reactor Coolant Flow-Low-One Loop as follows:

a. As Specified in CTS 2.3.2.B, CTS Table 3.5-2, Function 8(a), Low Flow One Loop, must be Operable when > 50% RTP (above the P-8 interlock setpoint) because a reactor trip on loss of flow in one loop is required only if > 50% RTP. ITS 3.3.1, Function 9, which includes both the one loop and two loop Reactor Coolant Flow-Low trip is required to be Operable whenever either the one loop or two loop trip is required (i.e., above the P-7 interlock setpoint). This Applicability is maintained by ITS Table 3.3.1-1, Note (e). ITS 3.3.1, Function 17.c, Power Range Flux, P-8, maintains the allowance that the reactor trip on loss of flow in one loop may be bypassed when < 50% RTP (See ITS 3.3.1, DOC A.28). Therefore, there is no change to the CTS Applicability for CTS Table 3.5-2, Function 8(a), Low Flow One Loop.

b. CTS Table 3.5-2, Functions 8 and 9, require 2 operable channels per loop with a minimum degree of redundancy of 1 operable channel per loop. This combination creates a requirement for 3 channels per loop with no more than 1 channel per loop in trip and enforces an unstated requirement that an inoperable channel be placed in trip (see 3.3.1, DOC A.34). ITS LCO 3.3.1, Function 9, requires 3 channels per loop and associated Required Action H.1 requires that an inoperable channel be placed in trip. Therefore, there is no

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1 Note: CTS CTS Table 3.5-2, Function 8(b), Low Flow Two Loops (Power < P-8 and ≥ P-10) should read (Power < P-8 and ≥ P-7) as shown in Dwg 113E301, Rev 9.

change to the existing requirements for minimum number of operable channels or minimum degree of redundancy except that the requirements are enforced by the combination of a requirement for a minimum number of channels and a specific requirement to place an inoperable channel in trip.

c. If requirements for minimum number of channels or minimum level of redundancy are not met, CTS Table 3.5-2 (footnote *) requires that the plant "maintain or proceed to hot shutdown within 4 hours using normal operating procedures." IP3 interprets this requirement as reactor shutdown must commence within 4 hours and completed (i.e., Mode 3) within the following 4 to 6 hours.

Under the same conditions, ITS LCO 3.3.1, Required Action H.2 (if there is a loss of redundancy), or ITS LCO 3.0.3 (if there is a loss of function), allow 6 or 7 hours, respectively, to reduce power less < P-7 setpoint (i.e., place the plant outside the Applicability for the Function). The requirement to place the plant outside of the Applicable Mode versus Mode 3 is an administrative change because it is a reasonable interpretation of the equivalent CTS requirement. The reduction in the Completion Time (elimination of the 4 hour delay until shutdown is started) is a more restrictive change (See ITS 3.3.1, DOC M.5).

CTS 3.5.4 allows a channel to be bypassed for up to 8 hours for testing without taking Actions for an inoperable channel if Function trip capability is maintained. ITS LCO 3.3.1, Note to Required Actions for Condition H, maintains this allowance for surveillance testing and setpoint adjustment of other channels. This testing allowance was justified in WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.

d. CTS Table 4.1-1, Item 5, Reactor Coolant Flow, requires a channel check every shift; ITS SR 3.3.1.1 maintains this requirement at the same Frequency by requiring a channel check every 12 hours.

CTS Table 4.1-1, Item 5, requires a channel test every quarter; ITS SR 3.3.1.7 maintains the requirement to perform a Channel Operation Test (COT) at a Frequency of 92 days.

CTS Table 4.1-1, Item 5, requires a channel calibration every 24 months; ITS SR 3.3.1.10 maintains the requirement to perform a Channel Calibration at a Frequency of 24 months.

e. CTS 2.3.1.B(6)(a) establishes the trip setpoint limiting safety system setting (allowable value) for the for the Reactor Coolant Flow-Low trip (both one loop and two loops) at ≥ 90% of normal indicated loop flow. This LSSS is based on the Indian Point Nuclear Generating Station Unit No. 3 Plant Manual, Volume VI: Precautions, Limitations, and Setpoints, March 1975. ITS 3.3.1, Function 9, Reactor Coolant Flow-Low (trip), establishes the allowable value at ≥ 89% of normal indicated loop flow because ITS uses allowable values calculated in accordance with Engineering Standards Manual IES-3 and IES 3-B, Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3) (See ITS 3.3.1, DOC L.1).

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated description and justification.

A.14 **ITS 3.3.1, Function 9, Reactor Coolant Flow-Low (trip) (two loop),** replaces the following two CTS Functions:

a. CTS Table 3.5-2, Function 8(a), Low Flow One Loop (Power ≥ P-8); and,

b. CTS Table 3.5-2, Function 8(b), Low Flow Two Loops (Power < P-8 and ≥ P-10[2]).

The ITS specifies that there is one Reactor Coolant Flow-Low trip and that this trip function is modified by plant conditions as follows:

a. Trip occurs on loss of flow in one loop if ≥ P-8 (i.e., 50% RTP);

b. Trip does not occur until there is a loss of flow in two loops if RTP is < P-8; and,

c. Trip does not occur on a loss of flow if < P-10 (i.e., 10% RTP).

The ITS conversion modifies the CTS requirements for Reactor Coolant

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2. Note: CTS CTS Table 3.5-2, Function 8(b), Low Flow Two Loops (Power < P-8 and ≥ P-10) should read (Power < P-8 and ≥ P-7) as shown on Dwg. 113E301, Rev 9.)

Flow-Low-Two Loop as follows:

a. CTS 2.3.2.A specifies that this Function shall be unblocked when (1) Power range nuclear flux ≥ 10% of rate power, or (2) Turbine first stage pressure ≥ 10% of equivalent full load (i.e., Function must be automatically unblocked above the P-7 interlock). ITS 3.3.1, Function 9, requires this function operable in Mode 1 and associated Note (e) specifies that this Function is required only when above the P-7 (Low Power Reactor Trip Block) interlock. ITS 3.3.1, Function 17.c, Power Range Flux, P-8, maintains the allowance that the reactor trip on loss of flow in one loop may be bypassed when < 50% RTP (See ITS 3.3.1, DOC A.28).

b. (See ITS 3.3.1, DOC A.13.b)

c. (See ITS 3.3.1, DOC A.13.c)

d. (See ITS 3.3.1, DOC A.13.d)

e. (See ITS 3.3.1, DOC A.13.e)

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated description and justification.

A.15 **ITS 3.3.1, Function 10.a, Reactor Coolant Pump (RCP) Breaker Position-Single Loop**, is derived from CTS 2.3.1.B.6(b) and CTS Table 3.5-2, Item 11, 6.9 kV Bus Underfrequency. In the ITS, **CTS 2.3.1.B.6(b) and CTS Table 3.5-2, Item 11, 6.9 kV bus Underfrequency trip function**, is divided into three different functions as follows:

Function 10.a, RCP Breaker Position, Single Loop: (DOC A.15)
A single open RCP breaker is required to cause a reactor trip if the plant is above P-8 interlock (>50% RTP)

Function 10.b, RCP Breaker Position, Two Loop: (DOC A.16)
Two open RCP breakers are required to cause a reactor trip if the plant is above P-7 interlock (>10% RTP)

Function 12, Underfrequency RCPs: (DOC A.18)
Underfrequency on two or more 6.9 kV buses is required to cause all four RCP breakers to open.

The ITS conversion establishes **ITS 3.3.1, Function 10.a, Reactor Coolant Pump (RCP) Breaker Position-Single Loop**, based on CTS 2.3.1.B.6(b) and CTS Table 3.5-2, Item 11, 6.9 kV bus Underfrequency trip function, when above P-8 interlock (>50% RTP) as follows:

a. CTS 2.3.2.B indirectly specifies that this Function may be bypassed when ≤ 50% of rated power (P-8 interlock setpoint) (i.e., loss of flow in a single loop will not result in a trip when ≤ 50% of rated power) because this Function is an anticipatory trip for the loss of coolant flow function. This is also consistent with the Applicability of CTS Table 3.5-2, Item 8, Low Flow-One Loop, which the RCP breaker trip function is intended to anticipate. ITS requires this function operable in Mode 1 and associated Note (f) specifies that this Function is required only when above the P-8 (Power Range Neutron Flux) interlock. Therefore, there is no change to the Applicability of this Function.

b. CTS Table 3.5-2 requires 3 operable channels with a minimum degree of redundancy of 2. This combination creates a requirement for 4 channels (1 channel per RCP breaker) and requires that an inoperable channel be restored to Operable rather than placed in trip (see 3.3.1, DOC A.34) because placing an inoperable channel in trip would cause a RCP trip and a reactor trip. Therefore, ITS 3.3.1, Function 10.a, restates the requirement for minimum operable channels as "1 per RCP" and associated Required Action I.1 requires that an inoperable channel be restored to Operable (see 3.3.1, DOC A.34) within 6 hours (see 3.3.1, DOC L.3). Therefore, there is no change to the existing requirements for minimum number of operable channels or minimum degree of redundancy except these requirements are enforced by the combination of a requirement for a minimum number of channels and a specific requirement to restore an inoperable channel to Operable status (versus placing it in trip which would cause a reactor trip).

c. CTS 3.5.4 specifies that the requirements for minimum Operable channels and minimum degree of redundancy be maintained by placing an inoperable channel in trip or, in this chase, restoring the channel to Operable. No Completion Time is specified but one hour to complete this task is a reasonable interpretation of the exiting requirement. Under the same conditions, ITS LCO 3.3.1, Required Action I.1, allows 6 hours to restore an inoperable channel. This is a less restrictive change justified in WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990 (See ITS 3.3.1, DOC L.3).

If requirements for minimum number of channels or minimum level of redundancy are not met, CTS Table 3.5-2 (footnote *) requires that the plant "maintain or proceed to hot shutdown within 4 hours using normal operating procedures." IP3 interprets this requirement as reactor shutdown must commence within 4 hours and completed (i.e., Mode 3) within the following 4 to 6 hours. Under the same conditions, ITS LCO 3.3.1, Required Action I.2 (if there is a loss of redundancy), or ITS LCO 3.0.3 (if there is a loss of function), allow 6 or 7 hours, respectively, to be in Mode 3. This is a more restrictive change (See ITS 3.3.1, DOC M.5).

CTS 3.5.4 allows a channel to be bypassed for up to 8 hours for testing without taking Actions for an inoperable channel if Function trip capability is maintained. ITS LCO 3.3.1, Note to Required Actions for Condition D, maintains this allowance for surveillance testing and setpoint adjustment of other channels. This testing allowance was justified in WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.

d. CTS Table 4.1-1, Item 8, (as it relates to the RCP Breaker position portion of the 6.9 kV Underfrequency Function), requires a channel calibration every 24 months. This is interpreted to require verification that a reactor trip results when any RCP breaker is opened when the P-8 interlock is not set to bypass this function. ITS SR 3.3.1.13 maintains the requirement to perform a Trip Actuating Device Operational Test (TADOT) at a Frequency of 24 months. ITS SR 3.3.1.14 is modified by a Note that provides an exception to the definition of a TADOT that is needed because RCP

Breaker position does not have a setpoint (other than opened or closed).

e. There is no allowable value or setpoint associated with this function.

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated description and justification.

A.16 **ITS 3.3.1, Function 10.b, Reactor Coolant Pump (RCP) Breaker Position-Two Loops**, is derived from CTS 2.3.1.B.6(b) and CTS Table 3.5-2, Item 11, 6.9 kV bus Underfrequency (see ITS 3.3.1, DOC A.15).

The ITS conversion establishes **ITS 3.3.1, Function 10.b, Reactor Coolant Pump (RCP) Breaker Position-Two Loop**, based on CTS 2.3.1.B.6(b) and CTS Table 3.5-2, Item 11, 6.9 kV bus Underfrequency trip function, as follows:

a. CTS 2.3.2.A indirectly specifies that this Function may be bypassed when ≤ 10% of rated power (P-7 interlock setpoint) (i.e., loss of flow in two loops will not result in a trip when ≤ 10% of rated power) because this Function is an anticipatory trip for the loss of coolant flow function. This is also consistent with the Applicability of CTS Table 3.5-2, Item 8, Low Flow-Two Loops, which the RCP breaker trip function is intended to anticipate. ITS requires this function operable in Mode 1 and associated Note (g) specifies that this Function is required only when above the P-7 (Low Power Reactor Trip Block) interlock. Additionally, Note (g) specifies that this Function is not required when above the P-8 setpoint. This is acceptable because ITS 3.3.1, Function 10.a, provides the anticipatory trip for loss of flow when above P-8 setpoint. Therefore, there is no change to the Applicability of this Function.

b. Changes to requirements for minimum number of Operable channels for ITS 3.3.1, Function 10.b, Reactor Coolant Pump (RCP) Breaker Position-Two Loop, based on CTS 2.3.1.B.6(b) and CTS Table 3.5-2,

Item 11, 6.9 kV bus Underfrequency trip function, are described in DOC 15.b.

c. CTS 3.5.4 specifies that the requirements for minimum Operable channels and minimum degree of redundancy be maintained by placing an inoperable channel in trip. No Completion Time is specified but one hour to complete this task is a reasonable interpretation of the exiting requirement. Under the same conditions, ITS LCO 3.3.1, Required Action H.1, allows 6 hours to place the inoperable channel in trip. This is a less restrictive change justified in WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990 (See ITS 3.3.1, DOC L.3).

If requirements for minimum number of channels or minimum level of redundancy are not met, CTS Table 3.5-2 (footnote *) requires that the plant "maintain or proceed to hot shutdown within 4 hours using normal operating procedures." IP3 interprets this requirement as reactor shutdown must commence within 4 hours and completed (i.e., Mode 3) within the following 4 to 6 hours.

Under the same conditions, ITS LCO 3.3.1, Required Action H.2 (if there is a loss of redundancy), or ITS LCO 3.0.3 (if there is a loss of function), allow 6 or 7 hours, respectively, to reduce power less < P-7 setpoint (i.e., place the plant outside the Applicability for the Function). The requirement to place the plant outside of the Applicable Mode versus Mode 3 is an administrative change because it is a reasonable interpretation of the equivalent CTS requirement. The reduction in the Completion Time (elimination of the 4 hour delay until shutdown is started) is a more restrictive change (See ITS 3.3.1, DOC M.5).

CTS 3.5.4 allows a channel to be bypassed for up to 8 hours for testing without taking Actions for an inoperable channel if Function trip capability is maintained. ITS LCO 3.3.1, Note to Required Actions for Condition H, maintains this allowance for surveillance testing and setpoint adjustment of other channels. This testing allowance was justified in WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.

d. Changes to Surveillance requirements CTS Table 4.1-1, Item 8, (as it relates to the RCP Breaker position portion of the 6.9 kV Underfrequency Function), for **ITS 3.3.1, Function 10.b, Reactor Coolant Pump (RCP) Breaker Position-Two Loop**, are discussed in DOC A.15.d.

e. There is no allowable value or setpoint associated with this function.

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated description and justification.

A.17 **ITS 3.3.1, Function 11, Undervoltage RCPs (6.9 kV bus)**, is equivalent to CTS 2.3.1.B(7) and CTS Table 3.5-2, Function 10, Undervoltage 6.9 kV Bus. The ITS conversion modifies the CTS requirements for Undervoltage RCPs (6.9 kV bus) as follows:

a. CTS 2.3.2.A indirectly specifies that this Function may be bypassed when ≤ 10% of rated power (P-7 interlock setpoint) (i.e., loss of flow in two loops will not result in a trip when ≤ 10% of rated power) because this Function is an anticipatory trip for the loss of coolant flow function. This is also consistent with the Applicability of CTS Table 3.5-2, Item 8, Low Flow (both one Loop and two loops), which the undervoltage trip function is intended to anticipate. ITS requires this function operable in Mode 1 and associated Note (e) specifies that this Function is required only when above the P-7 (Low Power Reactor Trip Block) interlock. Therefore, there is no change to the Applicability of this Function.

b. CTS Table 3.5-2 requires 3 operable channels with a minimum degree of redundancy of 2. This combination creates a requirement for 4 channels (1 channel per RCP bus) and requires that an inoperable channel be placed in trip. Therefore, ITS 3.3.1, Function 11, restates the requirement for minimum operable channels as "1 per bus" (i.e., 4 operable channels) and associated Required Action H.1 requires that an inoperable channel be placed in trip.

Therefore, there is no change to the existing requirements for minimum number of operable channels or minimum degree of redundancy except that the requirements are enforced by the combination of a requirement for a minimum number of channels and a specific requirement to place an inoperable channel in trip.

c. CTS 3.5.4 specifies that the requirements for minimum Operable channels and minimum degree of redundancy be maintained by placing an inoperable channel in trip. No Completion Time is specified but one hour to complete this task is a reasonable interpretation of the exiting requirement. Under the same conditions, ITS LCO 3.3.1, Required Action H.1, allows 6 hours to place the inoperable channel in trip. This is a less restrictive change justified in WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990 (See ITS 3.3.1, DOC L.3).

If requirements for minimum number of channels or minimum level of redundancy are not met, CTS Table 3.5-2 (footnote *) requires that the plant "maintain or proceed to hot shutdown within 4 hours using normal operating procedures." IP3 interprets this requirement as reactor shutdown must commence within 4 hours and completed (i.e., Mode 3) within the following 4 to 6 hours.

Under the same conditions, ITS LCO 3.3.1, Required Action H.2 (if there is a loss of redundancy), or ITS LCO 3.0.3 (if there is a loss of function), allow 6 or 7 hours, respectively, to reduce power less < P-7 setpoint (i.e., place the plant outside the Applicability for the Function). The requirement to place the plant outside of the Applicable Mode versus Mode 3 is an administrative change because it is a reasonable interpretation of the equivalent CTS requirement. The reduction in the Completion Time (elimination of the 4 hour delay until shutdown is started) is a more restrictive change (See ITS 3.3.1, DOC M.5).

CTS 3.5.4 allows a channel to be bypassed for up to 8 hours for testing without taking Actions for an inoperable channel if Function trip capability is maintained. ITS LCO 3.3.1, Note to Required Actions for Condition H, maintains this allowance for surveillance testing and setpoint adjustment of other channels.

This testing allowance was justified in WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.

d. CTS Table 4.1-1, Item 8, 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, requires a channel calibration of the undervoltage relay every 18 months; ITS SR 3.3.1.10 maintains the requirement to perform a Channel Calibration at a Frequency of 18 months.

e. CTS 2.3.1.B(7) establishes the trip setpoint limiting safety system setting (allowable value) for the Undervoltage 6.9 kV Bus at ≥70% of the normal voltage. This LSSS is based on the Indian Point Nuclear Generating Station Unit No. 3 Plant Manual, Volume VI: Precautions, Limitations, and Setpoints, March 1975. ITS 3.3.1, Function 11, Undervoltage RCPs (6.9 kV bus), establishes the allowable value at 68.37% of the nominal voltage because ITS uses allowable values calculated in accordance with Engineering Standards Manual IES-3 and IES 3-B, Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3) (See ITS 3.3.1, DOC L.1).

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated description and justification.

A.18 **ITS 3.3.1, Function 12, Underfrequency RCPs (6.9 kV bus)**, is equivalent to CTS 2.3.1.B(6)(b) and CTS Table 3.5-2, Item 11, Low Frequency 6.9 kV Bus. The ITS conversion modifies the CTS requirements for Underfrequency RCPs (6.9 kV bus) as follows:

a. CTS 2.3.2.A indirectly specifies that this Function may be

bypassed when ≤ 10% of rated power (P-7 interlock setpoint) (i.e., loss of flow in two loops will not result in a trip when ≤ 10% of rated power) because this Function is an anticipatory trip for the loss of coolant flow function. This is also consistent with the Applicability of CTS Table 3.5-2, Item 8, Low Flow (both one loop and two loops), which the underfrequency trip function is intended to anticipate. ITS requires this function operable in Mode 1 and associated Note (e) specifies that this Function is required only when above the P-7 (Low Power Reactor Trip Block) interlock. Therefore, there is no change to the Applicability of this Function.

b. CTS Table 3.5-2 requires 3 operable channels with a minimum degree of redundancy of 2. This combination creates a requirement for 4 channels (1 channel per RCP bus) and requires that an inoperable channel be placed in trip. Therefore, ITS 3.3.1, Function 12, restates the requirement for minimum operable channels as "1 per bus" (i.e., 4 operable channels) and associated Required Action H.1 requires that an inoperable channel be placed in trip. Therefore, there is no change to the existing requirements for minimum number of operable channels or minimum degree of redundancy except that the requirements are enforced by the combination of a requirement for a minimum number of channels and a specific requirement to place an inoperable channel in trip.

c. CTS 3.5.4 specifies that the requirements for minimum Operable channels and minimum degree of redundancy be maintained by placing an inoperable channel in trip. No Completion Time is specified but one hour to complete this task is a reasonable interpretation of the exiting requirement. Under the same conditions, ITS LCO 3.3.1, Required Action H.1, allows 6 hours to place the inoperable channel in trip. This is a less restrictive change justified in WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990 (See ITS 3.3.1, DOC L.3).

If requirements for minimum number of channels or minimum level of redundancy are not met, CTS Table 3.5-2 (footnote *) requires that the plant "maintain or proceed to hot shutdown within 4 hours using normal operating procedures." IP3 interprets this

requirement as reactor shutdown must commence within 4 hours and completed (i.e., Mode 3) within the following 4 to 6 hours.

Under the same conditions, ITS LCO 3.3.1, Required Action H.2 (if there is a loss of redundancy), or ITS LCO 3.0.3 (if there is a loss of function), allow 6 or 7 hours, respectively, to reduce power less < P-7 setpoint (i.e., place the plant outside the Applicability for the Function). The requirement to place the plant outside of the Applicable Mode versus Mode 3 is an administrative change because it is a reasonable interpretation of the equivalent CTS requirement. The reduction in the Completion Time (elimination of the 4 hour delay until shutdown is started) is a more restrictive change (See ITS 3.3.1, DOC M.5).

CTS 3.5.4 allows a channel to be bypassed for up to 8 hours for testing without taking Actions for an inoperable channel if Function trip capability is maintained. ITS LCO 3.3.1, Note to Required Actions for Condition H, maintains this allowance for surveillance testing and setpoint adjustment of other channels. This testing allowance was justified in WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.

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

e. CTS 2.3.1.B(6.b) establishes the trip setpoint limiting safety system setting (allowable value) for the for the Underfrequency 6.9 kV Bus trip at > 57.2 cps (cycles per second). This LSSS is

based on the Indian Point Nuclear Generating Station Unit No. 3 Plant Manual, Volume VI: Precautions, Limitations, and Setpoints, March 1975. ITS 3.3.1, Function 12, Underfrequency 6.9 kV Bus trip, establishes the allowable value at > 57.2 Hertz because ITS uses allowable values calculated in accordance with Engineering Standards Manual IES-3 and IES 3-B, Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3) (See ITS 3.3.1, DOC L.1).

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated description and justification.

A.19 **ITS 3.3.1, Function 13, Steam Generator (SG) Water Level Low Low,** is equivalent to CTS 2.3.1.C(2) and CTS Table 3.5-2, Function 9, Lo Lo Steam Generator (SG) Water Level. The ITS conversion modifies the CTS requirements for Steam Generator (SG) Water Level Low Low as follows:

a. CTS 3.5 does not specify an Applicability for this Function but CTS Table 3.5-2 establishes an implied Applicability by requiring that the plant be in hot shutdown (Mode 3) if requirements cannot be met. ITS requires this function operable in Modes 1 and 2. Therefore, there is no change to the existing Applicability requirement.

b. CTS Table 3.5-2 requires 2 channels per loop with a minimum degree of redundancy of 1 channel per loop. This combination creates a requirement for 3 channels per loop with no more than 1 channel per loop in trip and enforces an unstated requirement that an inoperable channel be placed in trip (see 3.3.1, DOC A.34). ITS 3.3.1, Function 13, Steam Generator (SG) Water Level Low Low, requires 3 channels per steam generator (SG) for each of the 4 SGS and Required Action E.1 will also require that an inoperable channel be placed in trip. Therefore, there is no change to the existing requirements for minimum number of operable channels or minimum degree of redundancy except that the requirements are enforced by the combination of a requirement for a minimum number of channels and a specific requirement to place an inoperable channel in trip.

c. CTS 3.5.4 specifies that the requirements for minimum Operable channels and minimum degree of redundancy be maintained by placing an inoperable channel in trip. No Completion Time is specified but one hour to complete this task is a reasonable interpretation of the exiting requirement. Under the same conditions, ITS LCO 3.3.1, Required Action E.1, allows 6 hours to place the inoperable channel in trip. This is a less restrictive change justified in WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990 (See ITS 3.3.1, DOC L.3).

If requirements for minimum number of channels or minimum level of redundancy are not met, CTS Table 3.5-2 (footnote *) requires that the plant "maintain or proceed to hot shutdown within 4 hours using normal operating procedures." IP3 interprets this requirement as reactor shutdown must commence within 4 hours and completed (i.e., Mode 3) within the following 4 to 6 hours. Under the same conditions, ITS LCO 3.3.1, Required Action E.2 (if there is a loss of redundancy), or ITS LCO 3.0.3 (if there is a loss of function), allow 6 or 7 hours, respectively, to be in Mode 3. This is a more restrictive change (See ITS 3.3.1, DOC M.5).

CTS 3.5.4 allows a channel to be bypassed for up to 8 hours for testing without taking Actions for an inoperable channel if Function trip capability is maintained. ITS LCO 3.3.1, Note to Required Actions for Condition E, maintains this allowance for surveillance testing and setpoint adjustment of other channels. This testing allowance was justified in WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.

d. CTS Table 4.1-1, Item 10, requires a channel check every shift; ITS SR 3.3.1.1 maintains this requirement at the same Frequency by requiring a channel check every 12 hours.

CTS Table 4.1-1, Item 10, requires a channel test every quarter; ITS SR 3.3.1.7 maintains the requirement to perform a Channel Operation Test (COT) at a Frequency of 92 days.

CTS Table 4.1-1, Item 10, requires a channel calibration every 24

months: ITS SR 3.3.1.10 maintains the requirement to perform a Channel Calibration at a Frequency of 24 months.

e. CTS 2.3.1.C(2) establishes the trip setpoint limiting safety system setting (allowable value) for the for the Steam Generator (SG) Water Level Low Low at ≥ 5% of narrow range instrument span. This LSSS is based on the Indian Point Nuclear Generating Station Unit No. 3 Plant Manual, Volume VI: Precautions, Limitations, and Setpoints, March 1975. ITS 3.3.1, Function 13, Steam Generator (SG) Water Level Low Low, establishes the allowable value at ≥ 3.54% of narrow range instrument span because ITS uses allowable values calculated in accordance with Engineering Standards Manual IES-3 and IES 3-B, Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3) (See ITS 3.3.1, DOC L.1).

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated description and justification.

A.20 **ITS 3.3.1, Function 14, SG Water Level Low Coincident with Steam Flow/Feedwater Flow Mismatch**, is not required by the CTS because, as stated in the CTS Bases, steam-feedwater flow mismatch trip is not used in the transient and accident analysis (FSAR Section 14). ITS 3.3.1, Function 14, SG Water Level Low Coincident with Steam Flow/Feedwater Flow Mismatch, is included in the ITS because this Function is assumed to provide a diverse and/or redundant reactor trip initiation in response to a loss of feedwater event. The inclusion of the Function in the ITS is a more restrictive change (see 3.3.1, DOC M.9).

a. The Applicability for ITS 3.3.1, Function 14, SG Water Level Low Coincident with Steam Flow/Feedwater Flow Mismatch, is Modes 1 and 2 which is consistent with the function it is intended to anticipate, ITS 3.3.1, Function 13, Steam Generator (SG) Water Level Low Low.

b. ITS 3.3.1, Function 14, SG Water Level Low Coincident with Steam Flow/Feedwater Flow Mismatch, requires 2 channels of SG Water Level -Low per SG and 2 channels of Steam Flow/Feed Flow mismatch

per SG to ensure that a single failure will not prevent actuation.

c. ITS LCO 3.3.1, Required Action E.1, will allow 6 hours to place the inoperable channel in trip. This AOT is justified in WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.

If requirements for minimum number of channels or minimum level of redundancy are not met, ITS LCO 3.3.1, Required Action E.2 (if there is a loss of redundancy), or ITS LCO 3.0.3 (if there is a loss of function), will allow 6 or 7 hours, respectively, to be in Mode 3.

d. ITS SR 3.3.1.1 is added to require a channel check every 12 hours.

ITS SR 3.3.1.7 is added to require a Channel Operation Test (COT) at a Frequency of 92 days.

ITS SR 3.3.1.10 is added to a Channel Calibration at a Frequency of 24 months.

e. CTS does not establish an allowable value for SG Water Level Low Coincident with Steam Flow/Feedwater Flow Mismatch,

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 13, Steam Generator Water Level-Low Low, is used to bound the analysis for a loss of feedwater event. The allowable values required for OPERABILITY of this trip function is ≥ 3.54% for steam generator level (the same allowable value as the Steam Generator Water Level-Low Low) and ≥ 1.64 E+6 pounds per hour difference for the steam flow feed flow mismatch. The analytical limit for this function is not directly modeled in the accident analysis and, therefore, is based on engineering judgement.

A.21 **ITS 3.3.1, Function 15, Turbine Trip-Auto Stop Oil Pressure**, is equivalent to CTS 2.3.1.C(3) and CTS Table 3.5-2, Function 12, Turbine Trip: Low auto stop oil pressure. The ITS conversion modifies the CTS

requirements for Turbine Trip-Low Fluid Oil Pressure as follows:

a. CTS 3.5 does not specify an Applicability for this Function but CTS Table 3.5-2 establishes an implied Applicability by requiring that the plant be maintained below 10% of full power if requirements cannot be met. ITS requires this function operable in Mode 1 and associated Note (h) specifies that this Function is required only when above the P-7 (Low Power Reactor Trip Block) interlock. Therefore, there is no change to the Applicability of this Function.

b. CTS Table 3.5-2 requires 2 operable channels with a minimum degree of redundancy of 1. This combination creates a requirement for 3 channels with no more than 1 channel in trip and enforces an unstated requirement that an inoperable channel be placed in trip (see 3.3.1, DOC A.34). ITS requires 3 channels and associated Required Action J.1 requires that an inoperable channel be placed in trip within 6 hours (see 3.3.1, DOC L.3). Therefore, there is no change to the existing requirements for minimum number of operable channels or minimum degree of redundancy except these requirements are enforced by the combination of a requirement for a minimum number of channels and a specific requirement to place an inoperable channel in trip.

c. CTS 3.5.4 specifies that the requirements for minimum Operable channels and minimum degree of redundancy be maintained by placing an inoperable channel in trip. No Completion Time is specified but one hour to complete this task is a reasonable interpretation of the exiting requirement. Under the same conditions, ITS LCO 3.3.1, Required Action J.1, allows 6 hours to place the inoperable channel in trip. This is a less restrictive change justified in WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990 (See ITS 3.3.1, DOC L.3).

If requirements for minimum number of channels or minimum level of redundancy are not met, CTS Table 3.5-2 (footnote *) requires that the plant "maintain reactor power below 10% of full power." No Completion Time is specified. Under the same conditions, ITS LCO 3.3.1, Required Action J.2 (if there is a loss of redundancy), or

ITS LCO 3.0.3 (if there is a loss of function), allow 6 or 7 hours, respectively, to reduce power less < P-7 setpoint (i.e., place the plant outside the Applicability for the Function). The requirement to place the plant outside of the Applicable Mode versus Mode 3 is an administrative change because it is a reasonable interpretation of the equivalent CTS requirement.

CTS 3.5.4 allows a channel to be bypassed for up to 8 hours for testing without taking Actions for an inoperable channel if Function trip capability is maintained. ITS LCO 3.3.1, Note to Required Actions for Condition H, maintains this allowance for surveillance testing and setpoint adjustment of other channels. This testing allowance was justified in WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.

d. CTS Table 4.1-1, Item 21, requires a channel calibration every 24 months; ITS SR 3.3.1.10 maintains the requirement to perform a Channel Calibration at a Frequency of 24 months.

CTS Table 4.1-1, Item 21, does not include a specific requirement to verify Operability by actuation of the end device associated with the turbine trip function. ITS SR 3.3.1.15 is added to ensure that the turbine trip Function is verified Operable every 24 months. Adding an explicit requirement to verify Operability by actuation of the end device associated with the turbine trip function every 24 months is a more restrictive change (see 3.3.1, DOC M.8).

e. CTS 2.3.1.C(2) does not establish any trip setpoint limiting safety system setting (allowable value) for the for the Turbine Trip-Auto Stop Oil Pressure. ITS 3.3.1, Function 15,Turbine Trip-Auto Stop Oil Pressure, establishes the allowable value at ≤ 1.6 psig. This allowable value was calculated in accordance with Engineering Standards Manual IES-3 and IES 3-B, Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3). 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.

A.22 **ITS 3.3.1, Function 16, (Reactor Trip) Safety Injection (SI) Input from ESFAS**, is not specifically identified as a Reactor Protection System Function in the CTS. CTS treats this Function as part of the Reactor Protection Relay Logic (CTS Table 3.5-2, Item 14), and the Engineered Safety Features Initiation Relay Logic (CTS Table 3.5-3, Item 6) except as discussed below. The ITS conversion modifies the CTS requirements for a reactor trip initiation by a safety injection signal as follows:

a. CTS 3.5 does not specify an Applicability for this Function but CTS Table 3.5-2 (Reactor Protection Relay Logic) establishes an implied Applicability by requiring that the plant be in hot shutdown (Mode 3) if requirements cannot be met. (Applicability requirements associated with ESFAS do not apply because there is no need for a reactor trip signal except in Mode 1 and 2.) ITS requires this function operable in Modes 1 and 2. Therefore, there is no change to the existing Applicability requirement.

b. CTS Table 3.5-2 requires 2 operable channels with a minimum degree of redundancy of 1 for RPS and 2 operable trains with a minimum degree of redundancy of 1 for ESFAS. This combination creates a requirement for 2 trains and requires that an inoperable train be restored to Operable because placing an inoperable train in trip will cause a reactor trip (see 3.3.1, DOC A.34). Therefore, ITS 3.3.1, Function 16, restates the requirement for minimum operable channels as "2 trains" and associated Required Action K.1 requires that an inoperable train be restored to Operable (see 3.3.1, DOC A.34) within 6 hours (see 3.3.1, DOC L.3). Therefore, there is no change to the existing requirements for minimum number of operable channels or minimum degree of redundancy except these requirements are enforced by the combination of a requirement for a minimum number of channels and a specific requirement to restore a channel to Operable status (versus placing it in trip which would cause a reactor trip).

c. CTS 3.5.4 specifies that the requirements for minimum Operable channels and minimum degree of redundancy be maintained by placing an inoperable channel in trip or, in this chase, restoring the channel to Operable. No Completion Time is specified but one hour

to complete this task is a reasonable interpretation of the exiting requirement. Under the same conditions, ITS LCO 3.3.1, Required Action K.1, allows 6 hours to restore an inoperable channel. This is a less restrictive change justified in WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990 (See ITS 3.3.1, DOC L.3).

If requirements for minimum number of channels or minimum level of redundancy are not met, CTS Table 3.5-2 (footnote *) requires that the plant "maintain or proceed to hot shutdown within 4 hours using normal operating procedures." IP3 interprets this requirement as reactor shutdown must commence within 4 hours and completed (i.e., Mode 3) within the following 4 to 6 hours. Under the same conditions, ITS LCO 3.3.1, Required Action K.2 (if there is a loss of redundancy), or ITS LCO 3.0.3 (if there is a loss of function), allow 6 or 7 hours, respectively, to be in Mode 3. This is a more restrictive change (See ITS 3.3.1, DOC M.5).

CTS 3.5.4 allows a train to be bypassed for up to 8 hours for testing without taking Actions for an inoperable channel if Function trip capability is maintained. ITS LCO 3.3.1, Note to Required Actions for Condition K, maintains this allowance for surveillance testing and setpoint adjustment of other channels. This testing allowance was justified in WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.

d. CTS 4.5.A.1 requires an operational test of Safety Injection every 24 months. Specifically, CTS 4.5.A.1 requires that a test safety injection signal be applied to initiate operation of the system. The test will be considered satisfactory if control board indication and visual observations indicate that all components have received the safety injection signal in the proper sequence and timing, that is, the appropriate pump breakers shall have opened and closed, and the appropriate valves shall have completed their travel. ITS SR 3.3.1.14 requires a Trip Actuating Device Operational Test (TADOT) at a Frequency of 24 months. ITS SR 3.3.1.14 is modified by a Note that provides an exception to the definition of a TADOT that is needed because ESFAS Initiation does not have a setpoint (ESFAS either initiates or it does not).

e. The allowable values for ITS 3.3.1, Function 16, (Reactor Trip) Safety Injection (SI) Input from ESFAS, are determined as described in the Discussion of Changes for ITS LCO 3.3.2, ESFAS Instrumentation.

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated justification.

A.23 **ITS 3.3.1, Function 18, Reactor Trip Breakers**, is equivalent to CTS Table 3.5-2, Function 13, Reactor Trip Breakers (Note that ITS has a separate Function for the reactor trip breaker undervoltage and shunt trip mechanisms). The ITS conversion modifies the CTS requirements for Reactor Trip Breakers as follows:

a. CTS 3.5 does not specify an Applicability for this Function but CTS Table 3.5-2 establishes an implied Applicability by requiring that the plant be in hot shutdown (Mode 3) if requirements cannot be met. Additionally, CTS Table 3.5-2 (Note ****) establishes requirements to defeat rod withdrawal capability within 1 hour after the reactor is in Mode 3 for 48 hours as a result of an inoperable RTB. Therefore, CTS has an implied Applicability of Modes 1 and 2 and in Mode 3 if the Rod Control System is capable of rod withdrawal. ITS requires this function operable in Modes 1 and 2 and in Mode 3, 4 and 5 if the Rod Control System is capable of rod withdrawal or all rods are not fully inserted (ITS Table 3.3.1-1, Note b). Expansion of the applicability to include whenever all control rods are not fully inserted is a less restrictive change (see 3.3.1, DOC L.6).

CTS Table 3.5-2, Function 13, Reactor Trip Breakers, does not specify any requirements for the reactor bypass breakers; however, CTS Table 4.1-1, Item 40 (Remarks), establishes testing requirements for the reactor bypass breakers that are consistent with their intended Function of allowing testing of the reactor trip breakers. ITS 3.3.1, Function 18, Note (i), indicates that all requirements for the Reactor Trip Breakers also apply to any reactor trip bypass breakers that are racked in and closed for

bypassing an RTB. This change to the Applicability is an administrative change with no impact on safety because it is a reasonable interpretation of the existing requirements and is consistent with current practice.

b. CTS Table 3.5-2 requires 2 operable channels with a minimum degree of redundancy of 1. This combination creates a requirement for 2 channels and requires that an inoperable channel be restored to Operable because placing an inoperable channel in trip will cause a reactor trip (see 3.3.1, DOC A.34). Therefore, ITS 3.3.1, Function 18, restates the requirement for minimum operable channels as "2 trains" with a train defined as a trip breaker and reactor trip bypass breaker associated with a single RPS logic train (but only if a breaker is racked in, closed, and capable of supplying power to the CRD system).

ITS LCO 3.3.1, Required Action L.1, requires that an inoperable channel be restored to Operable (see 3.3.1, DOC A.34) within 1 hour if in Mode 1 or 2; and, ITS LCO 3.3.1, Required Action C.1, requires that an inoperable channel be restored to Operable within 48 hours if in Mode 3, 4 and 5 and the Rod Control System is capable of rod withdrawal or all rods are not fully inserted. These Mode 3, 4 and 5 requirements are consistent with CTS Table 3.5-2, Note **** except for the expansion of the Applicability (see 3.3.1, DOC L.6).

Therefore, there is no change to the existing requirements for minimum number of operable channels or minimum degree of redundancy except these requirements are enforced by the combination of a requirement for a minimum number of channels and a specific requirement to restore a channel to Operable status (versus placing it in trip which would cause a reactor trip).

c. If in Mode 1 or 2, CTS 3.5.4 specifies that the requirements for minimum Operable channels and minimum degree of redundancy be maintained by placing an inoperable channel in trip or, in this chase, restoring the train to Operable. No Completion Time is specified but one hour to complete this task is a reasonable interpretation of the exiting requirement. Under the same

conditions, ITS LCO 3.3.1, Required Action L.1, allows 1 hour to restore an inoperable channel. Therefore, there is not change to the existing requirement.

In Mode 3, Table 3.5-2 (footnote ****) requires that the channel be restored to Operable within 48 hours after the reactor is shutdown or rod withdrawal capability must be defeated within the following 1 hour. Under the same conditions, ITS LCO 3.3.1, Action C.1 and C.2, also allow 48 hours to restore all channels to Operable or withdrawal capability must be defeated within the following 1 hour.

d. CTS Table 4.1-1, Item 39, requires a test of the RTBs at a TM Frequency (At least every two months on a staggered test basis (i.e., one train per month)). ITS SR 3.3.1.4 maintains the same requirement with a Trip Actuating Device Operational Test (TADOT) at a Frequency of 31 days on a Staggered Test Basis. ITS SR 3.3.1.4 is modified by a Note that specifies that this test must be performed on the reactor trip bypass breaker prior to placing the bypass breaker in service. This allowance is consistent with CTS Table 4.1-1, Item 40, Remark 1.

   Note that CTS Table 4.1-1, Item 39, requires testing of the reactor trip breakers from the control room (CTS Note 2) every 24 months; and, CTS Table 4.1-1, Item 40(1), requires testing of the reactor trip bypass breakers from the control room (CTS Note 2) every 24 months. ITS SR 3.3.1.14 (and the associated Note) maintains the requirement to perform a Trip Actuating Device Operational Test (TADOT) at a Frequency of 24 months. However, ITS Table 3.3.1-1, includes this requirement as part of ITS 3.3.1, Function 1, Manual Reactor Trip.

e. There is no allowable value or setpoint associated with this function.

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated description and justification.

A.24 **ITS 3.3.1, Function 19, Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms**, is equivalent to CTS Table 3.5-2, Function 13, Reactor Trip Breakers. CTS differentiates between the breakers and the trip mechanisms by using Note*** to govern trip mechanism Required Actions; ITS defines the breakers and the redundant trip mechanisms as separate Functions. The ITS conversion modifies the CTS requirements for RTB undervoltage and shunt trip mechanisms as follows:

a. CTS 3.5 does not specify an Applicability for this Function but CTS Table 3.5-2 establishes an implied Applicability by requiring that the plant be in hot shutdown (Mode 3) if requirements cannot be met. Additionally, CTS Table 3.5-2 (Note ****) establishes requirements to defeat rod withdrawal capability within 1 hour after the reactor is in Mode 3 for 48 hours as a result of an inoperable RTB. Therefore, CTS has an implied Applicability of Modes 1 and 2 and in Mode 3 if the Rod Control System is capable of rod withdrawal. ITS requires this function operable in Modes 1 and 2 and in Mode 3, 4 and 5 if the Rod Control System is capable of rod withdrawal or all rods are not fully inserted (ITS Table 3.3.1-1, Note b). Expansion of the applicability to include whenever all control rods are not fully inserted is a less restrictive change (see 3.3.1, DOC L.6).

b. CTS Table 3.5-2 requires 2 operable channel with a minimum degree of redundancy of 1 and CTS Table 3.5-2, Note***, provides clarification that the undervoltage and shunt trip mechanisms are separate Functions. This combination creates a requirement for 2 channels of Undervoltage and 2 channels of shunt trip mechanisms and requires that an inoperable channel be restored to Operable because placing any inoperable channel in trip will cause a reactor trip (see 3.3.1, DOC A.34). Therefore, ITS 3.3.1, Function 18, restates the requirement for minimum operable channels as "1 each per RTB" with the word "each" indicating that the undervoltage and shunt trip are separate channels. Additionally, associated Required Action 0.1 requires that an inoperable channel be restored to Operable within 48 hours (see 3.3.1, DOC M.6) if in Mode 1 or 2. Therefore, there is no change to the existing requirements for minimum number of operable channels or minimum degree of redundancy except these requirements

are enforced by the combination of a requirement for a minimum number of channels and a specific requirement to restore a channel to Operable status (versus placing it in trip which would cause a reactor trip).

c. CTS Table 3.5-2 (footnote *** which governs the undervoltage and shunt trip) requires that a channel be restored to Operable within 72 hours if either the undervoltage and shunt trip (not both) are inoperable (i.e., trip capability maintained but redundancy lost). Under the same conditions (loss of redundancy but not trip function when in Modes 1 and 2), ITS LCO 3.3.1, Actions 0.1, allows 48 (see 3.3.1, DOC M.6) hours to restore a channel to operable.

If more than one channel is inoperable or the channel is not restored within 72 hours, CTS Table 3.5-2 (footnote *) requires hot shutdown (Mode 3) within 4 hours. Under the same conditions (loss of RTB trip capability by this function when in Modes 1 and 2), ITS LCO 3.3.1, requires a shutdown in accordance with LCO 3.0.3.

If inoperable channels are discovered when the plant is already in Mode 3, 4 or 5 and the Rod Control System is capable of rod withdrawal or all rods are not fully inserted, TS LCO 3.3.1, Actions C.1 and C.2, require restoration of the inoperable channel within 48 hours or that rod withdrawal capability be defeated within the following hour. However, ITS LCO 3.3.1, Action C.2.2, adds a new requirement to initiate action to immediately insert all control rods if the channel is not restored to Operable within 48 hours. The addition of ITS LCO 3.3.1, Action C.2, is an administrative change because it is a reasonable interpretation of the equivalent CTS requirement.

d. CTS Table 4.1-1, Item 39, requires a test of the RTBs at a TM Frequency (At least every two months on a staggered test basis (i.e., one train per month)). ITS SR 3.3.1.4 maintains the same requirement with a Trip Actuating Device Operational Test (TADOT) at a Frequency of 31 days on a Staggered Test Basis. ITS SR 3.3.1.4 is modified by a Note that specifies that this test must

be performed on the reactor trip bypass breaker prior to placing the bypass breaker in service. This allowance is consistent with CTS Table 4.1-1, Item 40, Remark 1.

Note that CTS Table 4.1-1, Item 39, requires testing of the reactor trip breakers from the control room (CTS Note 2) every 24 months; and, CTS Table 4.1-1, Item 40(1), requires testing of the reactor trip bypass breakers from the control room (CTS Note 2) every 24 months. ITS SR 3.3.1.14 (and the associated Note) maintains the requirement to perform a Trip Actuating Device Operational Test (TADOT) at a Frequency of 24 months. However, ITS Table 3.3.1-1, includes this requirement as part of ITS 3.3.1, Function 1, Manual Reactor Trip.

e. There is no Technical Specification allowable value or setpoint associated with this function.

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated description and justification.

A.25 **ITS 3.3.1, Function 20, Automatic Trip Logic**, is equivalent to CTS Table 3.5-2, Function 14, Reactor Protection Relay Logic. The ITS conversion modifies the CTS requirements for Reactor Protection Automatic Trip Logic as follows:

a. CTS 3.5 does not specify an Applicability for this Function but CTS Table 3.5-2 establishes an implied Applicability by requiring that the plant be in hot shutdown (Mode 3) if requirements cannot be met. Additionally, CTS Table 3.5-2 (Note ****) establishes requirements to defeat rod withdrawal capability within 1 hour after the reactor is in Mode 3 for 48 hours as a result of an inoperable RTB. Therefore, CTS has an implied Applicability of Modes 1 and 2 and in Mode 3 if the Rod Control System is capable of rod withdrawal. ITS requires this function operable in Modes 1 and 2 and in Mode 3, 4 and 5 if the Rod Control System is capable of rod withdrawal or all rods are not fully inserted (ITS Table 3.3.1-1, Note a). Expansion of the applicability to include whenever all control rods are not fully inserted is a less

restrictive change (see 3.3.1, DOC L.6).

b. CTS Table 3.5-2 requires 2 operable channel with a minimum degree of redundancy of 1. This combination creates a requirement for 2 channels (see 3.3.1, DOC A.34) and requires that an inoperable channel be restored to Operable because placing any inoperable channel in trip would cause a reactor trip. Therefore, ITS 3.3.1, Function 20, restates the requirement for minimum operable channels as "2 trains" and associated Required Action K.1 requires that an inoperable channel be restored to Operable (see 3.3.1, DOC A.34) within 6 hours (see 3.3.1, DOC L.1) if in Mode 1 or 2; and, ITS LCO 3.3.1, Required Action C.1, requires that an inoperable channel be restored to Operable within 48 hours if in Mode 3, 4 and 5 and the Rod Control System is capable of rod withdrawal or all rods are not fully inserted. These Mode 3, 4 and 5 requirements are consistent with CTS Table 3.5-2, Note **** except for the expansion of the Applicability (see 3.3.1, DOC M.1).

Therefore, there is no change to the existing requirements for minimum number of operable channels or minimum degree of redundancy except these requirements are enforced by the combination of a requirement for a minimum number of channels and a specific requirement to restore a channel to Operable status (versus placing it in trip which would cause a reactor trip).

c. If in Mode 1 or 2, CTS 3.5.4 specifies that the requirements for minimum Operable channels and minimum degree of redundancy be maintained by placing an inoperable channel in trip or, in this chase, restoring the train to Operable. No Completion Time is specified but one hour to complete this task is a reasonable interpretation of the exiting requirement. Under the same conditions, ITS LCO 3.3.1, Required Action K.1, allows 6 hours to restore an inoperable channel (see 3.3.1, DOC L.1).

In Mode 3, Table 3.5-2 (footnote ****) requires that the channel be restored to Operable within 48 hours after the reactor is shutdown or rod withdrawal capability must be defeated within the following 1 hour. Under the same conditions, ITS LCO 3.3.1, Action C.1 and C.2, also allow 48 hours to restore all channels

to Operable or withdrawal capability must be defeated within the following 1 hour.

d. CTS Table 4.1-1, Item 20.a, requires a test of the Reactor Protection Relay Logic at a TM Frequency (At least every two months on a staggered test basis (i.e., one train per month)). ITS SR 3.3.1.5 maintains the same requirement with a Actuation Logic Test at a Frequency of 31 days on a Staggered Test Basis.

e. There is no Technical Specification allowable value or setpoint associated with this function.

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated description and justification.

A.26 **ITS 3.3.1, Function 17.a, Intermediate Range (IRM) Neutron Flux (P-6),** automatically unblocks the SRM reactor trip (ITS 3.3.1, Function 4) when decreasing power when 2 of 2 IRM channel signals indicates neutron flux level is in the lower end of the IRM range. P-6 also provides a permissive that allows blocking the SRM reactor trip (ITS 3.3.1, Function 4, SRM Flux (trip), when at least 1 of the 2 IRM channel signals indicates neutron flux level is in the IRM range. ITS 3.3.1, Table 3.3.1-1, maintains these requirements as follows:

a. ITS 3.3.1, Function 17.a, is required to be Operable whenever the IRM is below the P-6 setpoint (i.e., whenever ITS 3.3.1, Function 4, SRM Flux (trip) is required). When taken in conjunction with ITS 3.3.1, Required Action M.1 (i.e., verify interlock is in the required state for plant conditions), the only requirement established by ITS 3.3.1, Function 17.a, is that ITS 3.3.1, Function 4, SRM Flux (trip) must be Operable when required.

b. ITS 3.3.1, Function 17.a, requires 2 Operable trains of the P-6 function. Note that only 1 channel of ITS 3.3.1, Function 3, Intermediate Range Neutron Flux (trip), is required to be Operable. When taken in conjunction with ITS 3.3.1, Required Action M.1 (i.e., verify interlock is in the required state for

plant conditions), the only requirement established by ITS 3.3.1, Function 17.a, is that ITS 3.3.1, Function 4, SRM Flux (trip) must be Operable when required.

c. ITS 3.3.1, Required Action M.1, specifies that if a channel is inoperable, the verify interlock is in the required state for plant conditions. When taken in conjunction with the Applicability of ITS 3.3.1, Function 17.a, (i.e., required to be Operable only when ITS 3.3.1, Function 4, SRM Flux (trip) is required to be Operable.), the only requirement established by ITS 3.3.1, Function 17.a, is that ITS 3.3.1, Function 4, SRM Flux (trip) must be Operable when required. Therefore, there is no change to the existing requirements.

d. 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.

e. The setpoint for ITS 3.3.1, Function 17.a, is not directly modeled in the accident analysis and, therefore, is based on engineering judgement. This implemented setpoint ensures that ITS 3.3.1, Function 4, SRM Flux (trip) is Operable until there is IRM indication (and trip protection provided by the IRM trip function) when increasing power and ensures that ITS 3.3.1, Function 4, SRM Flux (trip) is Operable before IRM indication is lost when decreasing power.

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated description and justification.

A.27 **ITS 3.3.1, Function 17.b, Low Power Reactor Trip Block (P-7)**, provides an interlock that enables various Reactor Protection System trips that are required only when operating above the P-7 setpoint (approximately 10% power) and disabling these trips when reactor power is below the P-7 setpoint. P-7 is generated by the combination of the P-10 Interlock (ITS 3.3.1, Function 17.d) which is generated from the power range neutron flux channels and the First Stage Turbine Pressure Channels (ITS

3.3.1, Function 17.e). ITS 3.3.1, Table 3.3.1-1, maintains these requirements as follows:

a. ITS 3.3.1, Function 17.b, P-7, is required to be Operable in Mode 1 to ensure that P-7 performs it design function of ensuring that the various ITS 3.3.1 Functions enabled by this interlock are enabled before exceeding the P-7 setpoint.

b. ITS 3.3.1, Function 17.b, requires 2 Operable trains of the P-7 function.

c. ITS 3.3.1, Required Action N.1, specifies that if a channel is inoperable, the operator must verify interlock is in the required state for plant conditions. Therefore, this requires that the various ITS 3.3.1 Functions enabled by this interlock are Operable when required.

d. 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

e. Setpoints for this interlock are derived from ITS 3.3.1, Function 17.d, Power Range Neutron Flux (P-10) and ITS 3.3.1, Function 17.e, Turbine First Stage Pressure (P-7 Input) (See ITS 3.3.1, DOCs A.29 and A.30).

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated description and justification.

A.28 **ITS 3.3.1, Function 17.c, Power Range Neutron Flux (P-8)**, is an interlock that automatically enables the Reactor Coolant Flow—Low (Single Loop) and RCP Breaker Position (Single Loop) reactor trip on low flow in one or more RCS loops on increasing power. This interlock automatically enforces requirements established by CTS 2.3.2.B. The P-8 interlock is actuated at approximately 50% RTP as determined by two-out-of-four NIS power range detectors. ITS 3.3.1, Table 3.3.1-1, maintains these requirements as follows:

a. ITS 3.3.1, Function 17.c, P-8, is required to be Operable in Mode 1 to ensure that P-8 performs it design function of ensuring that the ITS 3.3.1 Functions enabled by this interlock are enabled before exceeding the P-8 setpoint.

b. ITS 3.3.1, Function 17.c, requires 4 Operable channels of the P-8 function. Therefore, there is no change to the existing requirements.

c. ITS 3.3.1, Required Action N.1, specifies that if a channel is inoperable, the operator must verify interlock is in the required state for plant conditions. Therefore, this requires that the ITS 3.3.1 Functions enabled by this interlock are Operable when required. Therefore, there is no change to the existing requirements.

d. CTS Table 4.1-1, Item 1 (Remark 2), Nuclear Power Range, requires the testing for the P-8 Interlock consistent with the requirements for testing Nuclear Power Range instruments. ITS SR 3.3.1.11 and ITS SR 3.3.1.13 maintain this requirement and require periodic Channel Operation Test and Channel Calibrations for this interlock.

e. CTS 2.3.2.B establishes the trip setpoints for the P-8 interlock at nuclear flux < 50% of rated power. This allowable value was established based on Indian Point Nuclear Generating Station Unit No. 3 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, March 1975, and are considered conservative. ITS 3.3.1, Function 17.c, will maintain the CTS value as the allowable value.

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated description and justification.

A.29 **ITS 3.3.1, Function 17.d, Power Range Neutron Flux (P-10)**, is an interlock that automatically enables ITS 3.3.1, Function 2.b, Power Range Neutron Flux-Low (trip) and ITS 3.3.1, Function 3, Intermediate

Range Neutron Flux (trip) on decreasing power. This interlock also provides a permissive to block the SRM, IRM and the Power Range Neutron Flux-Low trips when increasing reactor power. This interlock automatically enforces requirements established by CTS 2.3.2.A.1 by serving as an input to P-7. The P-10 interlock is actuated at approximately 10% RTP as determined by two-out-of-four NIS power range detectors. ITS 3.3.1, Table 3.3.1-1, maintains these requirements as follows:

a. ITS 3.3.1, Function 17.d, P-10, is required to be Operable in Modes 1 and 2 to ensure that P-10 performs it design function of ensuring that SRM, IRM and the PR Neutron Flux-Low trips are actuated when required and can be blocked only when not needed.

b. ITS 3.3.1, Function 17.d, requires 4 Operable channels of the P-10 function. Therefore, there is no change to the existing requirements.

c. ITS 3.3.1, Required Action M.1, specifies that if a channel is inoperable, the verify interlock is in the required state for plant conditions. Therefore, this requires that the ITS 3.3.1 Functions enabled by this interlock are Operable when required. Therefore, there is no change to the existing requirements.

d. CTS Table 4.1-1, Item 1 (Remark 2), Nuclear Power Range, requires the testing for the P-10 Interlock consistent with the requirements for testing Nuclear Power Range instruments. ITS SR 3.3.1.11 and ITS SR 3.3.1.13 maintain this requirement and require periodic Channel Operation Test and Channel Calibrations for this interlock.

e. CTS 2.3.2.A establishes the trip setpoints for the P-10 interlock at nuclear flux < 10% of rated power. This allowable value was established based on Indian Point Nuclear Generating Station Unit No. 3 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, March 1975, and are considered conservative. ITS 3.3.1, Function 17.d, will maintain the CTS value as the allowable value.

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated description and justification.

A.30 **ITS 3.3.1, Function 17.e, Turbine First Stage Pressure (P-7 Input)**, is one of the inputs to the P-7 interlock which is an interlock that enables various Reactor Protection System trips that are required only when operating above the P-7 setpoint (approximately 10% power) and disabling these trip when reactor power is below the P-7 setpoint. This interlock automatically enforces requirements established by CTS 2.3.2.A.2. ITS 3.3.1, Table 3.3.1-1, maintains these requirements as follows:

a. ITS 3.3.1, Function 17.d, is required to be Operable in Mode 1 to ensure that P-7 performs it design function of ensuring that the various ITS 3.3.1 Functions enabled by this interlock are enabled before exceeding the P-7 setpoint.

b. ITS 3.3.1, Function 17.b, requires 2 Operable channels of the Turbine First Stage Pressure (P-7 Input) function.

c. ITS 3.3.1, Required Action N.1, specifies that if a channel is inoperable, the verify interlock is in the required state for plant conditions. Therefore, this requires that the various ITS 3.3.1 Functions enabled by this interlock are Operable when required.

d. CTS Table 4.1-1, Item 19, Turbine First Stage Pressure, requires daily Channels Checks, quarterly Channel Operational Tests, and 24 month Channels Calibrations. ITS SR 3.3.1.1, ITS SR 3.3.1.11 and ITS SR 3.3.1.13 maintain these requirements at the existing Frequency.

e. CTS 2.3.2.A.2 establishes the trip setpoints for the Turbine First Stage Pressure (P-7 Input) interlock at nuclear flux > 10% of rated power. This allowable value was established based on Indian Point Nuclear Generating Station Unit No. 3 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, March 1975, and are

considered conservative. ITS 3.3.1, Function 17.e will maintain the CTS value as the allowable value.

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated description and justification.

A.31 CTS 3.5.2 specifies that plant operation shall be permitted to continue in accordance with Tables 3.5-2 through 3.5-4 for instrumentation testing or instrumentation channel failure; and, no more than one channel of a particular protection channel set shall be tested at the same time. ITS establishes equivalent requirements and allowances by establishing specific Required Actions for each Function. Specifically, ITS 3.3.1, Required Actions (as modified by TSTF-135, Rev.2 (WOG-58), RPS and ESFAS Instrumentation) and associated Notes establishing time limits for testing, always require verification that the inoperable channel does not result in a loss of trip Function before allowable out of service time may be applied for testing or inoperability. Additionally, ITS Required Action Notes limit the number of channels made inoperable by testing by requiring that the trip function be maintained during testing (although redundancy may be lost). This is an administrative change with no impact on safety because there is no change to the existing requirements.

A.32 The Actions for ITS 3.3.1, Reactor Protection Instrumentation, are preceded by a Note that specifies: "Separate Condition entry is allowed for each channel." This allowance provides explicit recognition that the ITS is designed to allow completely separate re-entry into any Condition for each train and/or channel addressed by the Condition. This includes separate tracking of Completion Times based on this re-entry. This allowance is consistent with an unstated assumption in the CTS. Therefore, the addition of this Note is an administrative change with no impact on safety.

A.33 CTS 3.5.4 includes the allowance "In the case of three loop operation, the out-of-service channel is permitted to be bypassed during the test period." Additionally, CTS Table 3.5-2, Item 8, establish minimum

requirements based on the number Operable loops. These allowances are intended to support IP3 operation with fewer than 4 loops Operable and operating. These allowances are not included in the ITS because the current analysis does not support operation with fewer than 4 loops Operable and operating. This is an administrative change with no impact on safety because it eliminates an allowance that cannot be used because of other Technical Specification constraints.

A.34 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.

> Operable channel is defined in CTS 1.7.1 as a channel that will a generate a single protective action signal when required by a plant condition. This definition excludes any channel in the tripped condition. The CTS requirement for minimum operable channels is designed to ensure that sufficient channels are available to adequately monitor the associated plant condition.
>
> Minimum degree of redundancy is defined in CTS 1.8 as the difference between the number of operable channels and the number of channels which when tripped will cause an automatic system trip. The CTS requirement for minimum degree of redundancy is designed to ensure the required ability to tolerate random failures of protective and/or control circuits.

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.

ITS LCOs specify a only the minimum number of Required Channels (which includes all requirements for redundancy) and uses LCO Required Actions to specify that one required channel may be inoperable if placed in trip or restored to Operable within a specified allowable out of service time (AOT). The Required Actions are specific to each Function and specify the actions that will ensure that both the minimum number of channels and minimum level of redundancy are maintained when one or more channels

are inoperable.

In the ITS, requirements for the minimum number of Operable channels are enforced by the combination of a requirement for a minimum number of channels and a specific requirement to restore or trip an inoperable channel. 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.

A.35 CTS Table 3.5-2, Item 8(b), Low Flow Two Loops, specifies that the Function must be Operable "Power < P-8 and ≥ P-10." This function has interlocks that make it function < P-8 and ≥ P-7. CTS 2.3.2.A requires that the Low Flow Two Loop Function be unblocked when: (1) Power range nuclear flux ≥ 10% of rate power; or, (2) Turbine first stage pressure ≥ 10% of equivalent full load. This combination of requirements is defined as the P-7 interlock. Part (1) of this interlock, Power range nuclear flux ≥ 10% of rate power, is the P-10 interlock. Therefore, CTS table 3.5-2, Item 8(b), should specify the applicability using the P-7 interlock. This CTS error had no impact on plant safety because of the following: the P-7 and P-10 interlock have the same setpoint; the plant design correctly provides the interlock based on P-7; the FSAR correctly describes this feature and associated requirements. This discrepancy is corrected in ITS Function 9.b, Note (g). Neither the typographical error or this change have any impact on safety.

A.36 CTS Tables 3.5-2, 3.5-3 and 3.5-4 establish minimum requirements for protective instrumentation Operability and specifies the Required Actions if these requirements are not met. Typically, these Required Actions specify proceed to or "maintain hot shutdown." ITS LCO 3.3.1 and ITS LCO 3.3.2 specify specific Required Actions are designed to place the plant outside the Applicable Modes or conditions. This is an administrative change with no impact on safety because it is a reasonable interpretation of the existing requirement.

A.37 CTS 3.5.4 allows a channel to be bypassed for up to 8 hours for testing without taking Actions for an inoperable channel if Function trip

capability is maintained. ITS LCO 3.3.1, Notes to various Required Actions, maintains this allowance for surveillance testing and setpoint adjustment of other channels. This testing allowance was justified in WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.

Additionally, ITS LCO 3.3.1, Note 2 to Actions, clarifies this allowance as follows: When a channel or train is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 8 hours provided the associated Function maintains RPS trip capability.

This is an administrative change with no adverse impact on safety because it is a reasonable interpretation of the equivalent CTS requirement in CTS 3.5.4.

MORE RESTRICTIVE

M.1 ITS 3.3.1, Function 4, SRM Flux (trip), and ITS 3.3.1, Function 3, IRM Flux (trip), are added to require one channel of the SRM and one channel of the IRM trip function (as described in ITS 3.3.1, DOCs A.6 and A.7). This change is needed because these functions provide redundant protection to the Power Range Neutron Flux—Low Setpoint trip Function for an uncontrolled RCCA bank rod withdrawal accident from a subcritical condition during startup. One channel is acceptable because administrative controls also prevent the uncontrolled withdrawal of rods. This change is acceptable because it does not introduce any operation which is unanalyzed while requiring more conservative requirements for redundant protection to the Power Range Neutron Flux—Low Setpoint trip Function for an uncontrolled RCCA bank rod withdrawal accident from a subcritical condition during startup. Therefore, this change has no adverse impact on safety.

M.2 CTS Table 3.5-2, Function 1, Manual Reactor Yrip (sic), requires 1 operable channel with a minimum degree of redundancy of zero. ITS 3.3.1, Function 1, Manual Reactor Trip, requires 2 operable channels so that no single random failure will disable the Manual Reactor Trip Function. This more restrictive change is needed because the Manual

Reactor Trip Function is designed with redundant capability although Functions such as manual reactor trip are not specifically credited in the accident safety analysis. Redundancy is needed because this Function is qualitatively credited in the safety analysis and the NRC staff approved licensing basis for the unit. Additionally, manual trip Functions provide protection for conditions that do not require dynamic transient analysis to demonstrate Function performance. Manual Functions also serve as backups to Functions that were credited in the accident analysis.

In conjunction with the new requirement for 2 manual trip channels, ITS LCO 3.3.1, Actions B.1 and C.1, will allow 48 hours to restore an inoperable channel when one of the two channels is inoperable. Allowing 48 hours to restore an inoperable manual trip is acceptable because the remaining Operable channel is adequate to perform the safety function. Therefore, 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. This change is acceptable because it does not introduce any operation which is un-analyzed while requiring redundant manual reactor trip capability. Therefore, this change has no adverse impact on safety.

M.3 CTS 3.5 does not specify an Applicability for Manual Reactor Trip Function but CTS Table 3.5-2 establishes an implied Applicability by requiring that the plant be in hot shutdown (Mode 3) if requirements cannot be met. ITS 3.3.1, Function 1, requires this function operable in Modes 1 and 2 and in Mode 3, 4 and 5 if the Rod Control System is capable of rod withdrawal or all rods are not fully inserted (ITS Table 3.3.1-1, Note a). Expanding the Applicability for Manual Reactor Trip Function to include Mode 3, 4 and 5 if the Rod Control System is capable of rod withdrawal and one or more rods are not fully inserted is a more restrictive change. This change is needed because having the Manual Reactor Trip Function is prudent whenever control rods are not fully inserted. Additionally, inadvertent control rod withdrawal is possible unless the Control Rod Drive (CRD) System is made not capable of withdrawing rods when in Mode 3, 4 and 5. In Mode 6, the CRDMs are normally disconnected from the control rods or control rods are not

otherwise permitted to be withdrawn. Therefore, the manual initiation Function is not required in Mode 6.

In conjunction with expanding the Applicability of the Manual Trip Function, ITS 3.3.1, Required Actions C.2.1 and C.2.2, are added to require that all control rods be fully inserted and that the control rod drive system be made incapable of rod withdrawal whenever Mode 3, 4 or 5 requirements or completion times cannot be met. ITS 3.3.1, Required Actions C.2.1 and C.2.2, place the plant outside the expanded Applicability.

Although ITS 3.3.1, Condition C, applies when one of the two manual trip functions is inoperable, Required Actions C.2.1 and C.2.2, and the associated 48 hour AOT will apply when both manual trip channels are inoperable in Modes 3, 4 and 5 because defaulting to LCO 3.0.3 will not place the plant outside of the Applicable Mode and conditions. This is acceptable because of the low probability of an event requiring manual trip capability when in these Modes.

This change is acceptable because it does not introduce any operation which is un-analyzed while requiring manual reactor trip capability whenever the Rod Control System is capable of rod withdrawal or all rods are not fully inserted. This change has no adverse impact on safety.

M.4 When in Mode 2, ITS SR 3.3.1.8 establishes a new requirement to perform a COT for ITS 3.3.1, Function 4, SRM Neutron Flux (trip), within 8 hours after reducing power below the P-6 (IRM Flux interlock) setpoint (See ITS 3.3.1, DOC A.7). Additionally, ITS SR 3.3.1.8 includes a new requirement to perform a COT for ITS 3.3.1, Function 3, IRM Neutron flux (trip), within 16 hours after reducing power below the P-10 setpoint (See ITS 3.3.1, DOC A.6). These changes are needed because they ensure that the COT will verify function Operability if the plant expects to stay critical, while allowing this SR to be skipped if the reactor shutdown will be completed promptly. Finally, when in Modes 3, 4 or 5 with CRD system capable of rod withdrawal and one or more rods not fully inserted, ITS SR 3.3.1.7 establishes a new requirement to perform a COT for ITS 3.3.1, Function 4, within 8 hours after entering Mode 3 from Mode 2 and every 92 days thereafter. This change is needed because the

source range trip is the only RPS automatic protection function required in MODES 3, 4, and 5.

This change is acceptable because it does not introduce any operation which is un-analyzed while prompt verification of the Operability of the required IRM and SRM trip functions after entering the Applicable mode. This change has no adverse impact on safety.

M.5 This change eliminates 4 hours from the time required to initiate plant shutdown when requirements for RPS instrument channel redundancy are not restored within the required Completion Time or there is a loss of a required RPS instrument trip function.

Specifically, if requirements for minimum number of channels or minimum level of redundancy are not met, CTS Table 3.5-2 (footnote *) requires that the plant "maintain or proceed to hot shutdown within 4 hours using normal operating procedures." IP3 interprets this requirement as reactor shutdown must commence within 4 hours and completed (i.e., Mode 3) within the following 4 to 6 hours. Under the same conditions, ITS LCO 3.3.1, Required Actions for failure to restore required redundancy within the specified Completion Time (if there is a loss of redundancy), or ITS LCO 3.0.3 (if there is a loss of function), allow 6 or 7 hours, respectively, to be in Mode 3.

This change is needed when there is a loss of instrument function because it ensures that the plant is promptly placed outside the Applicable Mode when a safety function assumed in the accident analysis is not Operable. This change is needed when requirements for RPS instrument channel redundancy are not restored within the required Completion Time to ensure the assumptions of WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990, are met regarding the availability of required RPS Functions.

This change is acceptable because it does not introduce any operation which is un-analyzed while ensuring that the Applicable Mode is exited promptly when requirements for RPS instrument redundancy or availability are not met. This change has no adverse impact on safety.

M.6 CTS Table 3.5-2 (footnote *** which governs the undervoltage and shunt trip) requires that a channel be restored to Operable within 72 hours if either the undervoltage and shunt trip (not both) are inoperable (i.e., trip capability maintained but redundancy lost). Under the same conditions (loss of redundancy but not trip function in Modes 1 and 2), ITS LCO 3.3.1, Actions O.1, allows 48 hours to restore a channel to operable. This change is made to establish consistency with Completion Times for loss of redundancy with similar Functions such as manual trip capability. The Completion Time of 48 hours for Required Action O.1 is reasonable because there is one remaining diverse feature for the affected RTB in this Condition, and there is one Operable RTB capable of performing the safety function and there is a low probability of an event occurring during this Completion Time. This change is acceptable because it does not introduce any operation which is un-analyzed while requiring more timely action if there is a loss of redundancy in reactor trip capability. Therefore, this change has no adverse impact on safety.

M.7 CTS Table 4.1-1, Items 1, 2 and 3, do not include explicit requirements Channel Calibration of the Power Range Neutron Flux (trip), IRM Flux (trip), or SRM Flux (trip), respectively, although the trip setpoints are verified as part of the operational tests. ITS SR 3.3.1.11 is added to require a Channel Calibration of these trip functions every 24 months. For the power range detectors, Channel Calibration consists of both a normalization of the detectors based on a power calorimetric and a flux map performed above 15% RTP. For the source range and intermediate range neutron detectors, Channel Calibration consists of obtaining the detector plateau or preamp discriminator curves, evaluating those curves, and comparing the curves to the manufacturer's data. This change is acceptable because it does not introduce any operation which is un-analyzed while establishing an explicit requirement for periodic calibration of the source, intermediate and power range nuclear detectors.. Therefore, this change has no adverse impact on safety.

M.8 CTS Table 4.1-1, Item 21, does not include an explicit requirement to verify operability by actuation of the end device associated with the

turbine trip function. ITS SR 3.3.1.14 is added to ensure that the turbine trip Function is Operable every 24 months, consistent with calibration requirements for the actuation instrumentation. This change is acceptable because it does not introduce any operation which is un-analyzed while establishing an explicit requirement for periodic verification of the end device associated with the turbine trip function. Therefore, this change has no adverse impact on safety.

M.9 ITS 3.3.1, Function 14, SG Water Level Low Coincident with Steam Flow/Feedwater Flow Mismatch, is not required by the CTS because, as stated in the CTS Bases, steam-feedwater flow mismatch trip is not used in the transient and accident analysis (FSAR Section 14). ITS 3.3.1, Function 14, SG Water Level Low Coincident with Steam Flow/Feedwater Flow Mismatch, is included in the ITS. This change is needed because this Function is assumed to provide a diverse and/or redundant reactor trip initiation in conjunction with SG Water Level Low (ITS 3.3.1, Function 13, Steam Generator (SG) Water Level Low Low) in response to a loss of feedwater event. This change is acceptable because it does not introduce any operation which is un-analyzed while establishing an explicit requirement for a diverse and/or redundant reactor trip function in response to a loss of feedwater event.

M.10 CTS 2.3.2.A specifies that reactor trips on low pressurizer pressure, high pressurizer level, low reactor coolant flow for two or more loops, and turbine trip must be unblocked when specified conditions are met. CTS 2.3.2.B specifies that single loop loss of flow reactor trips may be bypassed when the power range nuclear instrumentation indicates < 50% RTP. Although each of these requirements is enforced by an automatic interlock function, CTS does not explicitly require Operability of the interlock function. ITS 3.3.1, Function 17, Reactor Protection System Interlocks, is added to require Operability of the following: 17.a, Intermediate Range Neutron Flux (P-6) Interlock; 17.b, Low Power Reactor Trips Block (P-7) Interlock; 17.c, Power Range Neutron Flux (P-8) Interlock; 17.d, Power Range Neutron Flux (P-10) Interlock; and 17.e, Turbine First Stage Pressure (P-7 Input) interlock. If any of these interlocks is not Operable, ITS 3.3.1, Required Actions M.1 and N.1, require that the interlock be established consistent with plant

conditions. This is consistent with the CTS requirements. Therefore, this change has no adverse impact on safety.

LESS RESTRICTIVE

L.1 CTS trip setpoint limiting safety system setting (allowable value) are based on the IP3 Plant Manual, Volume VI: Precautions, Limitations, and Setpoints, March 1975. ITS will use allowable values calculated in accordance with Engineering Standards Manual IES-3 and IES 3-B, Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3). This change is needed because the limiting safety system settings established by IP3 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 Engineering Standards Manual IES-3 and IES 3-B, Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3) 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 CTS 3.5.2 specifies the following: "No more than one channel of a particular protection channel set shall be tested at the same time. By definition, an instrumentation channel failure shall not be regarded as a channel being tested." ITS LCO 3.0.5 establishes an allowance for restoring equipment to service under administrative controls when it has been removed from service or declared inoperable to comply with Actions. The purpose of this Specification is to provide an exception to LCO 3.0.2 (e.g., to not comply with the applicable Required Action(s)) to allow the performance of SRs to demonstrate: (a)The Operability of

the equipment being returned to service; or (b) The Operability of other equipment. The ITS Bases for LCO 3.0.5 include the example of this allowance as taking an inoperable channel or trip system out of the tripped condition to prevent the trip function from occurring during the performance of an SR on another channel in the other trip system. A similar example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to permit the logic to function and indicate the appropriate response during the performance of an SR on another channel in the same trip system. Therefore, ITS LCO 3.0.5 supersedes these restrictions in CTS 3.5.2. This change is acceptable because of the following: (1) ITS 3.3.1, Required Actions and associated Notes establishing time limits for testing, assumes there will be verification that the inoperable channel does not result in a loss of trip Function before allowable out of service time may be applied for testing or inoperability; (2) the duration in test (and therefore, time without single failure tolerance) is limited; and (3) the Westinghouse analog channel fault tree analysis used in WCAP-10271 assumes that more than one channel will be tested at a time. Therefore, this change has no significant impact on safety.

L.3 CTS 3.5.3 and CTS 3.5.4 specify that if requirements for minimum number of channels and/or minimum degree of redundancy cannot be achieved, than the actions specified for that Function, typically plant shutdown, must be initiated immediately (usually interpreted as within one hour). The combination of requirements for minimum number of channels and/or minimum degree of redundancy typically requires that the first inoperable channel for a Function be placed in trip to meet requirements and requires a plant shutdown when a second channel on a single function becomes inoperable. Under the same conditions, ITS 3.3.1 (as modified by TSTF-135 (WOG-58), RPS and ESFAS Instrumentation), Required Actions, allow 6 hours to restore a channel or place it in trip. In conjunction with this change, ITS 3.3.1 (as modified by TSTF-135 (WOG-58)), Required Actions, always require verification that the inoperable channel does not result in a loss of trip Function before the 6 hour allowable out of service time may be applied. The need for and justification for this change is included in WCAP-10271, "Evaluation of Surveillance Frequencies and Out-of-Service Times for the Reactor Protection Instrumentation System" including Supplement 1, and WCAP-10271,

Supplement 2, "Evaluation of Surveillance Frequencies and Out of Service Times for the Engineered Safety Features Actuation Systems." This justification was approved by the NRC in Safety Evaluations dated February 1985 and February 1989. Confirmation of the applicability of WCAP-10271 to the Indian Point 3 design and operation has already been confirmed by the NYPA and reviewed by the NRC as part of Technical Specification Amendment 107, dated March 22, 1991.

L.4 CTS Table 4.1-1, Item 1, requires a channel test of the power range instruments every quarter with associated Note ** to Table 4.1-1 requiring this test to be performed not less than 30 days prior to a reactor startup. ITS SR 3.3.1.8 maintains the requirement to perform a COT prior to reactor startup but only if the SR has not been performed in the previous 92 days (i.e. at a 92 day Frequency)

CTS Table 4.1-1, Item 2 (Frequency P(2)), requires that IRM response to a simulated signal (i.e., Channel Operational Test) be performed "prior to each startup if not performed in the previous week." ITS SR 3.3.1.8 maintains the requirement to perform a COT; however, the Frequency is extended to 92 days.

ITS 3.3.1 requires that Surveillance Tests be performed at the normal periodic Frequency only and tests are not required to be repeated prior to a specific event, such as a reactor startup. This change is acceptable because the normal periodic Surveillance Frequency is established to provide adequate assurance of the Operability of the instruments that provide these Functions. ITS SR 3.0.4 ensures that the required Surveillances have been performed within the normal specified interval prior to entering an applicable Mode or Condition. Additionally, there are redundant channels and any substantial degradation of the Power Range Neutron Flux-Low of a channel will be evident prior to the scheduled performance of these tests because of the following: Technical Specifications require Channel Checks on redundant Operable channels; and, Power Range Instrument response to reactivity changes is distinctive and well known to plant operators and nuclear instrumentation response is closely monitored during reactivity changes. Therefore, this change has no impact on safety.

L.5 CTS Table 4.1-1, Item 1 (Remark 3 with Note *), requires that the monthly calibration of the power range channels include a comparison of the upper and lower axial offset using the incore detectors. ITS SR 3.3.1.3 maintains the requirement to compare results of the incore detector measurements to NIS AFD; however, the Frequency is extended from once per month to every 31 effective full power days (EFPD). Additionally, CTS Table 4.1-1, Item 1 (Remark 3 with Note *), requires a calibration of the excore channels to the incore channels every month. ITS SR 3.3.1.6 maintains the requirement to calibrate the excore channels to the incore channels; however, the Frequency is extended from once per month to every 31 EFPDs. Extending the Frequency for ITS SR 3.3.1.3 and ITS SR 3.3.1.6 from monthly to every 31 EFPDs is acceptable because these SRs are intended to detect and make adjustments for relatively slow changes in flux patterns that are a function of core exposure. Therefore, the SR Frequency is being changed to a function of core exposure with an interval consistent with the current SR Frequency if the plant is operated at full power during the SR interval. Operating experience indicates that this Frequency is sufficient to compensate for the slow changes in neutron flux patterns during this interval. These SRs are not intended to detect flux tilts that occur quickly (e.g., a dropped rod) for which there are other indications of abnormality that prompt a verification of core power tilt. Therefore, this change has no adverse impact on safety.

L.6 CTS Table 3.5-2 (Note ****) establishes requirements to defeat rod withdrawal capability within 1 hour after the reactor is in Mode 3 for 48 hours as a result of an inoperable RTB. Therefore, CTS has an implied Applicability of the Rod Control System is capable of rod withdrawal. ITS requires this function operable if the Rod Control System is capable of rod withdrawal and all rods are not fully inserted (ITS Table 3.3.1-1, Note b). Expansion of the applicability to include whenever all control rods are not fully inserted is a less restrictive change. This change is needed because it provides an alternative to opening the RTBs so that certain SRs can be performed (e.g., COTs on certain channels). This change is acceptable because having all control rods fully inserted meets the intent implied by opening the RTBs. Additionally, required reactor trip functions must be made Operable before any control rod can be withdrawn and the potential for a rod

withdrawal event is created. Therefore, this change has no adverse impact on safety.

REMOVED DETAIL

LA.1 CTS Section 3.5, Tables 3.5-2, 3.5-3 and 3.5-4, Columns 1 and 2, identify the number of channels and the channels required to trip for each RPS and ESFAS Function. ITS LCO 3.3.1, LCO 3.3.2, LCO 3.3.3, LCO 3.3.5 and LCO 3.3.6 require that these Functions be Operable but do not provide system design details. This is acceptable because this design information is incorporated into the minimum requirements and ITS specifies the minimum requirements for Operability.

This change is acceptable because ITS LCO 3.3.1, LCO 3.3.2, LCO 3.3.3, LCO 3.3.5 and LCO 3.3.6 maintain the existing requirements for the Operability of these instruments (except as identified and justified in this discussion of change); therefore, there is no change to the existing requirements and no change to the level of safety of facility operation.

This change, which allows the description of the design of instrument functions to be maintained in the FSAR and the detailed description of the requirements for Operability of these functions to be maintained in the ITS Bases, is consistent with the approach used in NUREG-1431 for all Limiting Conditions for Operation (LCOs). This approach is acceptable because the requirements of 10 CFR 50.59, Changes, Tests and Experiments, and ITS 5.5.13, Technical Specifications (TS) Bases Control Program, are designed to assure that changes to the FSAR and ITS Bases do not result in changes to the Technical Specification requirements and do not result in significant increases in the probability or consequences of accidents previously evaluated, do not create the possibility of a new or different kind of accident, and do not result in a significant reduction in a margin of safety. Additionally, IP3 programs that implement FSAR changes in accordance with 10 CFR 50.59 and ITS Bases changes in accordance with ITS 5.5.13 require periodic submittal of FSAR and Bases changes to the NRC for review.

This change is a less restrictive administrative change with no impact

on safety because no requirements are being deleted from Technical Specifications and an appropriate change control process and an appropriate level of regulatory oversight are maintained for the information being relocated out of the Technical Specifications.

LA.2 CTS Tables 3.5-2, 3.5-3 and 3.5-4 and 4.1-1 include remarks and clarification notes that are not directly related to the Operability of any RPS or ESFAS Function. 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 5.5.12, 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 NYPA 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.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.1:
"Reactor Protection System (RPS) Instrumentation"

PART 4:

No Significant Hazards Considerations
for
Changes between CTS and ITS
that are
Less Restrictive

No Significant Hazard Considerations for Changes that are Administrative, More Restrictive, and Removed Details are the same for all Packages. A Copy is included at the end of the Package.

NO SIGNIFICANT HAZARDS EVALUATION
ITS SECTION 3.3.1 - REACTOR TRIP SYSTEM (RTS) INSTRUMENTATION

LESS RESTRICTIVE
("L.1" Labeled Comments/Discussions)

New York Power Authority has evaluated the proposed Technical Specification change identified as "Less Restrictive" in accordance with the criteria set forth in 10 CFR 50.92, and has determined that the proposed change does not involve a significant hazards consideration. The bases for the determination that the proposed change does not involve a significant hazards consideration are discussed below.

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

   CTS trip setpoint limiting safety system setting (allowable value) are based on the IP3 Plant Manual, Volume VI: Precautions, Limitations, and Setpoints, March 1975. ITS will use allowable values calculated in accordance with Engineering Standards Manual IES-3 and IES 3-B, Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3). This change is needed because the limiting safety system settings established by IP3 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 will not result in a significant increase in the probability of an accident previously evaluated because a small change in the allowable value for an RPS or ESFAS actuation instrumentation is not assumed as the initiator of any accident previously evaluated. This change will not result in a significant increase in the consequences of an accident previously evaluated because the allowable values calculated in accordance with Engineering Standards Manual IES-3 and IES-3B, Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3). This methodology ensures 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 provides 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.

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

   The proposed change will not involve any physical changes to systems, structures, or components, or involve a change in normal plant operation. Therefore, it will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   This change does not involve a significant reduction in a margin of safety because the existing limiting safety system setting and the proposed allowable values use the information and methods available at the time to determine instrument settings that ensure that safety limits are not exceeded during any event.

LESS RESTRICTIVE
("L.2" Labeled Comments/Discussions)

New York Power Authority has evaluated the proposed Technical Specification change identified as "Less Restrictive" in accordance with the criteria set forth in 10 CFR 50.92, and has determined that the proposed change does not involve a significant hazards consideration. The bases for the determination that the proposed change does not involve a significant hazards consideration are discussed below.

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

   This change eliminates a restriction in current Technical Specifications that could preclude implementation of ITS LCO 3.0.5 which establishes an allowance for restoring equipment to service under administrative controls when it has been removed from service or declared inoperable to comply with Actions. This change will permit taking an inoperable channel or trip system out of the tripped condition to prevent the trip

function from occurring during the performance of an SR on another channel in the other trip system. This change will not result in a significant increase in the probability of an accident previously evaluated because the status of an RPS or ESFAS instrument channel is not assumed as the initiator of any accident previously evaluated. This change will not result in a significant increase in the consequences of an accident previously evaluated because of the following: (1) ITS 3.3.1 and 3.3.2, Required Actions and associated Notes establishing time limits for testing, require verification that the inoperable channel does not result in a loss of trip Function before allowable out of service time may be applied for testing or inoperability; and, (2) the duration in test is limited and, therefore, the time the channel cannot tolerate a single failure is limited.

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

   The proposed change will not involve any physical changes to systems, structures, or components, or involve a change in normal plant operation. Therefore, it will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   This change does not involve a significant reduction in a margin of safety because the Westinghouse analog channel fault tree analysis used in WCAP-10271 assumes that more than one channel will be tested at a time. Safety Evaluations for WCAP-10271 concluded that all of the changes justified in WCAP-10271 determined that an overall conservative upper bound for the core damage frequency (CDF) increase due to the proposed STI/AOT changes is slightly less than 6 percent for Westinghouse PWR plants. The staff also concluded that actual CDF increases for individual plants are expected to be substantially less than 6 percent. This CDF increase to be small compared to the range of uncertainty in the CDF analyses and therefore acceptable. Based on the WCAP-10271 analyses and subsequent NRC review, the NRC concluded that the proposed STI and AOT changes for the ESFAS and RTS would have only a small and, therefore, acceptable impact on overall plant risk.

NO SIGNIFICANT HAZARDS EVALUATION
ITS SECTION 3.3.1 - REACTOR TRIP SYSTEM (RTS) INSTRUMENTATION

LESS RESTRICTIVE
("L.3" Labeled Comments/Discussions)

New York Power Authority has evaluated the proposed Technical Specification change identified as "Less Restrictive" in accordance with the criteria set forth in 10 CFR 50.92, and has determined that the proposed change does not involve a significant hazards consideration. The bases for the determination that the proposed change does not involve a significant hazards consideration are discussed below.

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

   This change extends the allowable out of service time to restore or trip an inoperable channel from 1 hour to 6 hours if the inoperable channel does not result in a loss of the Function's trip capability. This change will not result in a significant increase in the probability of an accident previously evaluated because the status of an RPS or ESFAS instrument channel is not assumed as the initiator of any accident previously evaluated. This change will not result in a significant increase in the consequences of an accident previously evaluated because ITS 3.3.1 (as modified by TSTF-135 (WOG-58)), Required Actions, always require verification that the inoperable channel does not result in a loss of trip Function before the 6 hour allowable out of service time may be applied. Therefore, the Function is always Operable and the time that the Function cannot tolerate a single failure is limited based on the analysis in WCAP-10271, "Evaluation of Surveillance Frequencies and Out-of-Service Times for the Reactor Protection Instrumentation System" including Supplement 1, and WCAP-10271, Supplement 2, "Evaluation of Surveillance Frequencies and Out of Service Times for the Engineered Safety Features Actuation Systems."

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

   The proposed change will not involve any physical changes to systems, structures, or components, or involve a change in normal plant operation. Therefore, it will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

This change does not involve a significant reduction in a margin of safety because ITS 3.3.1 (as modified by TSTF-135 (WOG-58)), Required Actions, always require verification that the inoperable channel does not result in a loss of trip Function before the 6 hour allowable out of service time may be applied. Therefore, the Function is always Operable and the time that the Function cannot tolerate a single failure is limited based on the analysis in WCAP-10271, "Evaluation of Surveillance Frequencies and Out-of-Service Times for the Reactor Protection Instrumentation System" including Supplement 1, and WCAP-10271, Supplement 2, "Evaluation of Surveillance Frequencies and Out of Service Times for the Engineered Safety Features Actuation Systems." Safety Evaluations for WCAP-10271 concluded that all of the changes justified in WCAP-10271 determined that an overall conservative upper bound for the core damage frequency (CDF) increase due to the proposed STI/AOT changes is slightly less than 6 percent for Westinghouse PWR plants. The staff also concluded that actual CDF increases for individual plants are expected to be substantially less than 6 percent. This CDF increase to be small compared to the range of uncertainty in the CDF analyses and therefore acceptable. Based on the WCAP-10271 analyses and subsequent NRC review, the NRC concluded that the proposed STI and AOT changes for the ESFAS and RTS would have only a small and, therefore, acceptable impact on overall plant risk.

LESS RESTRICTIVE
("L.4" Labeled Comments/Discussions)

New York Power Authority has evaluated the proposed Technical Specification change identified as "Less Restrictive" in accordance with the criteria set forth in 10 CFR 50.92, and has determined that the proposed change does not involve a significant hazards consideration. The bases for the determination that the proposed change does not involve a significant hazards consideration are discussed below.

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

CTS Table 4.1-1, Item 1, requires a channel test of the power range

instruments every quarter with associated Note ** to Table 4.1-1 requiring this test to be performed not less than 30 days prior to a reactor startup. ITS SR 3.3.1.8 maintains the requirement to perform a COT prior to reactor startup but only if the SR has not been performed in the previous 92 days (i.e. at a 92 day Frequency)

CTS Table 4.1-1, Item 2 (Frequency P(2)), requires that IRM response to a simulated signal (i.e., Channel Operational Test) be performed "prior to each startup if not performed in the previous week." ITS SR 3.3.1.8 maintains the requirement to perform a COT; however, the Frequency is extended to 92 days.

This change will not result in a significant increase in the probability of an accident previously evaluated because the status of the Power Range Neutron Flux-Low Function is not assumed as the initiator of any accident previously evaluated. This change will not result in a significant increase in the consequences of an accident previously evaluated because there is a high degree of assurance that this Function will be Operable when required. This assurance results from the high degree of redundancy for this function (2 of 4 channels to trip). Additionally, the normal periodic Surveillance Frequency is established to provide adequate assurance of the Operability of the instruments that provide these Functions. Finally, any substantial degradation of the Power Range Neutron Flux-Low will be evident prior to the scheduled performance of these tests because of the following: Technical Specifications require Channel Checks on redundant Operable channels; and, Power Range Instrument response to reactivity changes is distinctive and well known to plant operators and nuclear instrumentation response is closely monitored during reactivity changes.

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

   The proposed change will not involve any physical changes to systems, structures, or components, or involve a change in normal plant operation. Therefore, it will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

This change does not involve a significant reduction in a margin of safety because there is a high degree of assurance that this Function will be Operable when required. This assurance results from the high degree of redundancy for this function (2 of 4 channels to trip). Additionally, any substantial degradation of the Power Range Neutron Flux-Low will be evident prior to the scheduled performance of these tests because of the following: Technical Specifications require Channel Checks on redundant Operable channels; and, Power Range Instrument response to reactivity changes is distinctive and well known to plant operators and nuclear instrumentation response is closely monitored during reactivity changes. Finally, the Power Range Neutron Flux-Low trip is supported by a diverse trip from the IRMs or SRMs which are being added to Technical Specifications as part of the conversion to ITS.

LESS RESTRICTIVE
("L.5" Labeled Comments/Discussions)

New York Power Authority has evaluated the proposed Technical Specification change identified as "Less Restrictive" in accordance with the criteria set forth in 10 CFR 50.92, and has determined that the proposed change does not involve a significant hazards consideration. The bases for the determination that the proposed change does not involve a significant hazards consideration are discussed below.

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

   This change extends the Surveillance Frequency for CTS Table 4.1-1, Item 1 (Remark 3 with Note *), which requires that the monthly calibration of the power range channels include a comparison of the upper and lower axial offset using the incore detectors. ITS SR 3.3.1.3 maintains the requirement to compare results of the incore detector measurements to NIS AFD; however, the Frequency is extended from once per month to every 31 effective full power days (EFPD). Additionally, CTS Table 4.1-1, Item 1 (Remark 3 with Note *), requires a calibration of the excore channels to the incore channels every month. ITS SR 3.3.1.6 maintains the requirement to calibrate the excore channels to the incore channels; however, the Frequency is extended from once per month to 31 EFPDs.

This change will not result in a significant increase in the probability of an accident previously evaluated because Surveillance Frequency is not assumed as the initiator of any accident previously evaluated. This change will not result in a significant increase in the consequences of an accident previously evaluated because these SRs are intended to detect and make adjustments for relatively slow changes in flux patterns that are a function of core exposure. Therefore, the SR Frequency is being changed to a function of core exposure with an interval consistent with the current SR Frequency if the plant is operated at full power during the SR interval. Operating experience indicates that this Frequency is sufficient to compensate for the slow changes in neutron flux patterns during this interval. These SRs are not intended to detect flux tilts that occur quickly (e.g., a dropped rod) for which there are other indications of abnormality that prompt a verification of core power tilt.

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

   The proposed change will not involve any physical changes to systems, structures, or components, or involve a change in normal plant operation. Therefore, it will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   This change does not involve a significant reduction in a margin of safety because these SRs are intended to detect and make adjustments for relatively slow changes in flux patterns that are a function of core exposure. Therefore, the SR Frequency is being changed to a function of core exposure with an interval consistent with the current SR Frequency if the plant is operated at full power during the SR interval. Operating experience indicates that this Frequency is sufficient to compensate for the slow changes in neutron flux patterns during this interval. These SRs are not intended to detect flux tilts that occur quickly (e.g., a dropped rod) for which there are other indications of abnormality that prompt a verification of core power tilt.

NO SIGNIFICANT HAZARDS EVALUATION
ITS SECTION 3.3.1 - REACTOR TRIP SYSTEM (RTS) INSTRUMENTATION

LESS RESTRICTIVE
("L.6" Labeled Comments/Discussions)

New York Power Authority has evaluated the proposed Technical Specification change identified as "Less Restrictive" in accordance with the criteria set forth in 10 CFR 50.92, and has determined that the proposed change does not involve a significant hazards consideration. The bases for the determination that the proposed change does not involve a significant hazards consideration are discussed below.

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

   CTS Table 3.5-2 (Note ****) establishes requirements to defeat rod withdrawal capability when there is an inoperable RTB. Therefore, CTS has an implied Applicability of the Rod Control System is capable of rod withdrawal. ITS requires this function operable if the Rod Control System is capable of rod withdrawal and all rods are not fully inserted (ITS Table 3.3.1-1, Note a). Expansion of the applicability to include whenever all control rods are not fully inserted is a less restrictive change. This change is needed because it provides an alternative to opening the RTBs so that certain SRs can be performed (e.g., COTs on certain channels). This change will not result in a significant increase in the probability of an accident previously evaluated because rod control system status when a reactor startup is not in progress is not assumed as the initiator of any accident previously evaluated. This change will not result in a significant increase in the consequences of an accident previously evaluated because required reactor trip functions must be made Operable before any control rod can be withdrawn.

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

   The proposed change will not involve any physical changes to systems, structures, or components, or involve a change in normal plant operation. Therefore, it will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

This change does not involve a significant reduction in a margin of safety because required reactor trip functions must be made Operable before any control rod can be withdrawn.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.1:
"Reactor Protection System (RPS) Instrumentation"

PART 5:

NUREG-1431
Annotated to show differences between
NUREG-1431 and ITS

Status of NUREG 1431 Generic Changes for ITS 3.3.1

This ITS Specification is based on NUREG-1431 Specification No. **3.3.1**
as modified by the following Generic Changes:

OG No.	TSTF No.	Generic Change Description	NRC STATUS	IP3 STATUS	JD No.
WOG-006	**019 R0**	RELOCATE THE DETAILS OF RTD AND THERMOCOUPLE CALIBRATION FROM THE CHANNEL CALIBRATION DEFINITION TO BASES OF INST. SPECS	NRC Review	Not Incorporated	**N/A**
WOG-052 R1	**111 R1**	REVISE BASES FOR SR 3.3.1.16 AND 3.3.2.10 TO ELIMINATE PRESSURE SENSOR RESPONSE TIME TESTING	NRC Review	Not Incorporated	**N/A**
WOG-058	**135 R0**	RPS AND ESFAS INSTRUMENTATION	Rejected by NRC	N/A	**N/A**
WOG-058 R1	**135 R1**	RPS AND ESFAS INSTRUMENTATION	Rejected by NRC	N/A	**N/A**
WOG-058 R2	**135 R2**	RPS AND ESFAS INSTRUMENTATION	NRC Review	Incorporated	**T.1**

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.1:
"Reactor Protection System (RPS) Instrumentation"

WOG-080	**169 R0**	DELETE CONDITION 3.3.1.N	Approved by NRC	Incorporated	**T.2**
WOG-082	**168 R0**	RTB MAINTENANCE	NRC Review	Not Incorporated	**N/A**

<(CTS)> 3.3 INSTRUMENTATION

3.3.1 Reactor Trip System (RTS) Instrumentation — Protection — RPS — (all locations)

<3.5.2> LCO 3.3.1 The RTS instrumentation for each Function in Table 3.3.1-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.1-1.

ACTIONS — Insert: 3.3-1-01 — 1.

<DOC A.32> ----------NOTE---------- (S)
Separate Condition entry is allowed for each Function.

	CONDITION	REQUIRED ACTION	COMPLETION TIME
<3.5.3>	A. One or more Functions with one or more required channels or trains inoperable.	A.1 Enter the Condition referenced in Table 3.3.1-1 for the channel(s) or train(s).	Immediately
<DOC A.3>	B. One Manual Reactor Trip channel inoperable.	B.1 Restore channel to OPERABLE status. OR B.2.1 Be in MODE 3. AND B.2.2 Open reactor trip breakers (RTBs).	48 hours 54 hours 55 hours

T.1

T.1

(continued)

ACTIONS (continued)

	CONDITION	REQUIRED ACTION	COMPLETION TIME
<DOC A.3> <DOC A.23> <DOC A.24> <DOC A.25>	C. One channel or train inoperable.	C.1 Restore channel or train to OPERABLE status.	48 hours
		OR	
	Insert: 3.3-2-01	C.2 ~~Open RTBs.~~	~~49 hours~~ T.1
<DOC A.4> <3.5.4>	D. One Power Range Neutron Flux—High channel inoperable.	----------NOTE---------- The inoperable channel may be bypassed for up to ~~4~~ 8 hours for surveillance testing and setpoint adjustment of other channels. ----------	
		D.1.1 Place channel in trip.	6 hours
		AND	
<3.10.2.9> <SEE ITS 3.2.4>		D.1.2 Reduce THERMAL POWER to ≤ 75% RTP.	~~12~~ 24 hours CLB.1
		OR	
		D.2.1 Place channel in trip.	6 hours
		AND	

(continued)

INSERT 3.3-2-01:

	C.2.1 Initiate action to fully insert all rods. AND C.2.2 Place the Rod control System in a condition incapable of rod withdrawal.	48 hours 49 hours

ACTIONS

	CONDITION	REQUIRED ACTION	COMPLETION TIME
<DOC A.4>	D. (continued)	----------NOTE---------- Only required to be performed when the Power Range Neutron Flux input to QPTR is inoperable. ----------	
<3.10.2.9> <SEE ITS 3.2.4>		D.2.2 Perform SR 3.2.4.2.	Once per 12 hours 24 CLB.1
		OR	
		D.3 Be in MODE 3.	12 hours
<DOC A.5> <DOC A.8> <DOC A.9> <DOC A.11> <DOC A.19> <DOC A.20> <3.5.4>	E. One channel inoperable.	----------NOTE---------- The inoperable channel may be bypassed for up to 4 hours for surveillance testing of other channels. ---------- 8	
		E.1 Place channel in trip.	6 hours
		OR	
		E.2 Be in MODE 3.	12 hours
	~~F. THERMAL POWER > P-6 and < P-10, one Intermediate Range Neutron Flux channel inoperable.~~	~~F.1 Reduce THERMAL POWER to < P-6.~~	~~2 hours~~
		~~OR~~	
		~~F.2 Increase THERMAL POWER to > P-10.~~	~~2 hours~~

CLB.1

(continued)

ACTIONS (continued)

	CONDITION	REQUIRED ACTION		COMPLETION TIME	
<DOC A.6>	F. ~~THERMAL POWER > P-6 and < P-10,~~ ~~two~~ Intermediate Range Neutron Flux channel~~s~~ inoperable. Required	F.1	Suspend operations involving positive reactivity additions.	Immediately	T.1 CLB.1
		AND			
		F.2	Reduce THERMAL POWER to < P-6.	2 hours	
	~~H. THERMAL POWER < P-6, one or two Intermediate Range Neutron Flux channels inoperable.~~	~~H.1~~	~~Restore channel(s) to OPERABLE status.~~	~~Prior to increasing THERMAL POWER to > P-6~~	T.1
	I. ~~One Source Range Neutron Flux channel inoperable.~~	I.1	~~Suspend operations involving positive reactivity additions.~~	~~Immediately~~	CLB.1
<DOC A.7>	G. ~~Two~~ Source Range Neutron Flux channel~~s~~ inoperable. Required	G.1	Open ~~RTBs.~~ Reactor Trip Breakers (RTBs)	Immediately	CLB.1 T.1
	~~K. One Source Range Neutron Flux channel inoperable.~~ Insert: 3.3-4-01	~~K.1~~	~~Restore channel to OPERABLE status.~~	~~48 hours~~	CLB.1
		OR			
		~~K.2~~	~~Open RTBs.~~	~~49 hours~~	T.1

(continued)

INSERT 3.3-4-01: (This Insert Not Used)

	K.2.1 Initiate action to fully insert all rods. AND K.2.2 Place the Rod control System in a condition incapable of rod withdrawal.	48 hours 49 hours

T.1

CLB.1

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
~~L~~. Required Source Range Neutron Flux channel[(s)] inoperable.	~~L~~.1 Suspend operations involving positive reactivity additions.	Immediately
	AND	
	~~L~~.2 Close unborated water source isolation valves.	1 hour
	AND	
	~~L~~.3 Perform SR 3.1.1.1.	1 hour AND Once per 12 hours thereafter
(H) ~~M~~. One channel inoperable.	----------NOTE---------- The inoperable channel may be bypassed for up to (4) hours for surveillance testing of other channels. ----------	(8)
	~~M~~.1 (H) Place channel in trip.	6 hours
	OR	
	~~M~~.2 (H) Reduce THERMAL POWER to < P-7.	12 hours

(DOC A.10)
(DOC A.12)
(DOC A.13)
(DOC A.14)
(DOC A.16)
(DOC A.17)
(DOC A.18)
(3.5.4)

(T.1)

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
N. One Reactor Coolant Flow - Low (Single Loop) channel inoperable.	----------NOTE---------- The inoperable channel may be bypassed for up to 4 hours for surveillance testing of other channels. ----------	
	N.1 Place channel in trip.	6 hours
	OR	
	N.2 Reduce THERMAL POWER to < P-8.	10 hours
I <DOC A.15> <3.5.4> Ø. One Reactor Coolant Pump Breaker Position channel inoperable.	----------NOTE---------- The inoperable channel may be bypassed for up to 4 hours for surveillance testing of other channels. ----------	8
	Ø.1 I Restore channel to OPERABLE status.	6 hours
	OR	
	Ø.2 I Reduce THERMAL POWER to < P-8.	10 hours

T.2

(continued)

ACTIONS (continued)

	CONDITION	REQUIRED ACTION	COMPLETION TIME
<DOC A.21>	J ~~F~~. One Turbine Trip channel inoperable.	----------NOTE---------- The inoperable channel may be bypassed for up to ~~4~~ 8 hours for surveillance testing of other channels. ----------	
		~~F~~.1 J Place channel in trip.	6 hours
		OR	
		~~F~~.2 J Reduce THERMAL POWER to < ~~P-9~~ P-7.	~~10~~ 12 hours CLB.1
<DOC A.22> <DOC A.25>	K ~~G~~. One train inoperable.	----------NOTE---------- One train may be bypassed for up to ~~4~~ 8 hours for surveillance testing provided the other train is OPERABLE. ----------	CLB.1 DB.1
		~~G~~.1 K Restore train to OPERABLE status.	6 hours
		OR	
		~~G~~.2 K Be in MODE 3.	12 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
<DOC A.23> (L) ~~K~~. One RTB train inoperable.	----------NOTES---------- 1. One train may be bypassed for up to 2 hours for ~~surveillance~~ testing, provided the other train is OPERABLE. 2. One RTB may be bypassed for up to 2 hours for maintenance on undervoltage or shunt trip mechanisms, provided the other train is OPERABLE. ----------	
	~~K~~.1 (L) Restore train to OPERABLE status.	1 hour
	OR	
	~~K~~.2 (L) Be in MODE 3.	7 hours
<DOC A.26> <DOC A.29> (M) ~~S~~. One channel inoperable. (or more channels)	~~S~~.1 (M) Verify interlock is in required state for existing unit conditions.	1 hour
	OR	
	~~S~~.2 (M) Be in MODE 3.	7 hours

(continued)

ACTIONS (continued)

	CONDITION	REQUIRED ACTION	COMPLETION TIME	
<DOC A.27> <DOC A.28> <DOC A.30>	N ~~T~~. One ~~channel~~ inoperable. or more channels	~~T~~.1 N Verify interlock is in required state for existing unit conditions.	1 hour	T.1
		OR		
		~~T~~.2 N Be in MODE 2.	7 hours	
<DOC A.29> <DOC M.6> <T 3.5-2, Note ***>	O ~~U~~. One trip mechanism inoperable for one RTB.	O ~~U~~.1 Restore inoperable trip mechanism to OPERABLE status.	48 hours	
		OR		
		~~U~~.2.1 O Be in MODE 3.	54 hours	
		AND		
		~~U~~.2.2 Open ~~RTB~~.	~~55 hours~~	T.1
	~~V~~. ~~Two RTS trains inoperable.~~	~~V~~.1 ~~Enter LCO 3.0.3.~~	~~Immediately~~	T.1

SURVEILLANCE REQUIREMENTS

<4.1.A>
<4.1.B>

NOTE
Refer to Table 3.3.1-1 to determine which SRs apply for each RTS Function.

	SURVEILLANCE	FREQUENCY
T4.1-1, Column "Check" SR 3.3.1.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.1.2 <DOC A.4.d> <DOC A.4.d>	NOTES 1. Adjust NIS channel if absolute difference is > 2%. 2. Not required to be performed until [12] hours after THERMAL POWER is ≥ 15% RTP. (24) <T4.1-1, #1> <DOC A.4> Compare results of calorimetric heat balance calculation to Nuclear Instrumentation System (NIS) channel output.	24 hours
SR 3.3.1.3 <3.11.B> <DOC A.8> <DOC L.5>	NOTES 1. Adjust NIS channel if absolute difference is ≥ 3%. 2. ~~Not required to be performed until [24] hours after THERMAL POWER is ≥ [15]% RTP~~ (Insert: 3.3-10-01) Compare results of the incore detector measurements to NIS AFD.	31 effective full power days (EFPD)

(continued)

INSERT 3.3-10-01:

Only required to be performed when THERMAL POWER is > 90% RTP. CLB.2

SURVEILLANCE REQUIREMENTS (continued)

<CTS>

SURVEILLANCE		FREQUENCY
SR 3.3.1.4 <DOC 23> <DOC 24>	----------NOTE---------- This Surveillance must be performed on the reactor trip bypass breaker prior to placing the bypass breaker in service. ---------- Perform TADOT.	31 days on a STAGGERED TEST BASIS
SR 3.3.1.5 <DOC A25>	Perform ACTUATION LOGIC TEST.	31 days on a STAGGERED TEST BASIS
SR 3.3.1.6 <3.11.B> Insert: 3.3-11-01	----------NOTE---------- ~~Not required to be performed until [24] hours after THERMAL POWER is ≥ 50% RTP.~~ ---------- Calibrate excore channels to agree with incore detector measurements.	(92) EFPD 31 CLB.1
SR 3.3.1.7 <DOC A.4> <DOC A.7> <DOC 12> <DOC A.8> <DOC 13> <DOC A9> <DOC 14> <DOC 10> <DOC 19> <DOC 11> <DOC A.20>	----------NOTE---------- Not required to be performed for source range instrumentation prior to entering MODE 3 from MODE 2 until (4) hours after entry into MODE 3. ---------- Perform COT.	8 [92] days

(continued)

INSERT 3.3-11-01:

Only required to be performed when THERMAL POWER is > 90% RTP.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.8	----------NOTE---------- This Surveillance shall include verification that interlocks P-6 and P-10 are in their required state for existing unit conditions. ----------	
	Perform COT.	-----NOTE----- Only required when not performed within previous ~~[92]~~ days ---------- Prior to reactor startup AND Sixteen ~~Four~~ hours after reducing power below P-10 for power and intermediate instrumentation AND Eight ~~Four~~ hours after reducing power below P-6 for source range instrumentation AND Every 92 days thereafter

<DOC L.4>
<DOC A.5>
<DOC A.6>
<DOC A.7>

(continued)

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE		FREQUENCY
<DOC A.17> <DOC A.18>	SR 3.3.1.9	----------NOTE---------- Verification of setpoint is not required. ---------- Perform TADOT.	~~[92]~~ days
<DOC A.17> <DOC A.18> <DOC A.20> <DOC A.21>	SR 3.3.1.10	----------NOTE---------- This Surveillance shall include verification that the time constants are adjusted to the prescribed values. ---------- Perform CHANNEL CALIBRATION.	Insert: 3.3-13-04 ~~[18] months~~ CLB.
<DOC A.4> <DOC A.5> <DOC 26> <DOC A.6> <DOC 27> <DOC A.7> <DOC 28> <DOC A.30> <DOC A.29>	SR 3.3.1.11	----------NOTE---------- Neutron detectors are excluded from CHANNEL CALIBRATION. ---------- Perform CHANNEL CALIBRATION.	~~[18]~~ 24 months
<DOC A.8> <DOC A.9>	SR 3.3.1.12	----------NOTE---------- ~~This Surveillance shall include verification of Reactor Coolant System resistance temperature detector bypass loop flow rate~~ Insert: 3.3-13-02 ---------- Perform CHANNEL CALIBRATION.	~~[18]~~ 24 months
DOC 26 DOC 27 <DOC 28> <DOC-22> <DOC A.26> <DOC A.27> <DOC A.28> <DOC 27> <DOC 28>	SR 3.3.1.13	Perform COT.	18 months 24

(continued)

NUREG-1431 Markup Inserts
ITS SECTION 3.3.1 - REACTOR PROTECTION SYSTEM (RPS) INSTRUMENTATION

INSERT 3.3-13-01:

24 months

AND

18 months for Function 11

INSERT 3.3-13-02:

This Surveillance shall include verification that the electronic dynamic compensation time constants are set at the required values.

INSERT 3.3-13-01:

This Surveillance shall include verification that the electronic dynamic compensation time constants are set at the required values.

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE		FREQUENCY
<DOC A.3> <T4.1-1, #39, #40> <DOC 15> <DOC 16> <DOC A.22>	SR 3.3.1.14	----------NOTE---------- Verification of setpoint is not required. ---------- Perform TADOT.	[18] 24 months
<DOC A.21> <DOC M.8>	SR 3.3.1.15	----------NOTE---------- Verification of setpoint is not required. ---------- Perform TADOT. 24 months	~~NOTE Only required when not performed within previous 31 days~~ ~~Prior to reactor startup~~ CLB.1
	SR 3.3.1.16	~~NOTE Neutron detectors are excluded from response time testing.~~ Verify RTS RESPONSE TIME is within limits.	~~[18] months on a STAGGERED TEST BASIS~~ CLB.1

Table 3.3.1-1 (page 1 of 8)
Reactor Trip System Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	~~TRIP SETPOINT(a)~~
<DOC A.3>	1. Manual Reactor Trip	1,2	2	B	SR 3.3.1.14	NA	NA
<DOC M.2> <DOC M.3>		3(β), 4(β), 5(β)	2	C	SR 3.3.1.14	NA	NA
	2. Power Range Neutron Flux						
<DOC A.4>	a. High	1,2	4	D	SR 3.3.1.1 SR 3.3.1.2 SR 3.3.1.7 SR 3.3.1.11 ~~SR 3.3.1.16~~	≤ ~~[111.2]~~% RTP (109)	≤ [109]% RTP
<DOC A.5>	b. Low	1(f),2	4	E	SR 3.3.1.1 SR 3.3.1.8 SR 3.3.1.11 ~~SR 3.3.1.16~~	≤ ~~[27.2]~~% RTP (25)	≤ [25]% RTP
	3. Power Range Neutron Flux Rate						
	a. High Positive Rate	1,2	4	E	SR 3.3.1.7 SR 3.3.1.11	≤ [6.8]% RTP with time constant ≥ [2] sec	≤ [5]% RTP with time constant ≥ [2] sec
	b. High Negative Rate	1,2	4	E	SR 3.3.1.7 SR 3.3.1.11 SR 3.3.1.16	≤ [6.8]% RTP with time constant ≥ [2] sec	≤ [5]% RTP with time constant ≥ [2] sec
<DOC A.6>	~~4.~~ 3. Intermediate Range Neutron Flux	1(f), 2(f)	2 1	F	SR 3.3.1.1 SR 3.3.1.8 SR 3.3.1.11	≤ [31]% RTP NA	≤ [25]% RTP
		2(e)	2	H	SR 3.3.1.1 SR 3.3.1.8 SR 3.3.1.11	≤ [31]% RTP	≤ [25]% RTP

(continued)

(a) ~~Reviewer's Note: Unit specific implementations may contain only Allowable Value depending on Setpoint Study methodology used by the unit.~~ (PA.1)

(a) (b) With ~~Reactor Trip Breakers (RTBs) closed and~~ Rod Control System capable of rod withdrawal. Insert: 3.3-15-01 (T.1)

(b) (c) Below the P-10 (Power Range Neutron Flux) interlocks.

(c) (d) Above the P-6 (Intermediate Range Neutron Flux) interlocks.

(e) ~~Below the P-6 (Intermediate Range Neutron Flux) interlocks.~~ (T.1)

INSERT 3.3-15-01:

or one or more rods not fully inserted.

Table 3.3.1-1 (page 2 of 8)
Reactor Trip System Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	~~TRIP SETPOINT~~[a]	
<DOC A.7>	4 ~~5.~~ Source Range Neutron Flux	d 2[d]	1 2	G I,J	SR 3.3.1.1 SR 3.3.1.8 SR 3.3.1.11 ~~SR 3.3.1.16~~	≤ [1.4 E5] cps NA	~~≤ [1.0 E5] cps~~	CLB.1
<DOC M.1>	a	3[b], 4[b], 5[b]	1 2	G J,K	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.11 ~~SR 3.3.1.16~~	≤ [1.4 E5] cps	~~≤ [1.0 E5] cps~~	
		~~3[f], 4[f], 5[f]~~	~~[1]~~	~~L~~	~~SR 3.3.1.1~~ ~~SR 3.3.1.11~~	~~N/A~~	~~N/A~~	
<DOC A.8>	5 ~~6.~~ Overtemperature ΔT	1,2	~~[4]~~	E	SR 3.3.1.1 SR 3.3.1.3 SR 3.3.1.6 SR 3.3.1.7 SR 3.3.1.12 ~~SR 3.3.1.16~~	Refer to Note 1 ~~(Page 3.3-21)~~	~~Refer to Note 1 (Page 3.3-21)~~	
<DOC A.9>	6 ~~7.~~ Overpower ΔT	1,2	~~[4]~~	E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.12 ~~SR 3.3.1.16~~	Refer to Note 2 ~~(Page 3.3-22)~~	~~Refer to Note 2 (Page 3.3-22)~~	

(continued)

~~(a) Reviewer's Note: Unit specific implementations may contain only Allowable Value depending on Setpoint Study methodology used by the unit.~~ PA.1

a ~~(b)~~ With ~~RTBs closed and~~ Rod Control System capable of rod withdrawal. Insert: 3.3-16-01 T.1

d ~~(c)~~ Below the P-6 (Intermediate Range Neutron Flux) interlocks.

~~(f) With the RTBs open. In this condition, source range function does not provide reactor trip but does provide input to the Boron Dilution Protection System (LCO 3.3.9), and indication.~~ T.1

INSERT 3.3-16-01:

~~or~~ one or more rods not fully inserted.
and

Table 3.3.1-1 (page 3 of 8)
Reactor Trip System Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	TRIP SETPOINT(a)
	~~8.~~ 7 Pressurizer Pressure						
<DOC A.10>	a. Low	1(g)	~~[4]~~ 4	H	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10 ~~SR 3.3.1.16~~	≥ ~~[1956]~~ 1749 psig	≥ [1900] psig
<DOC A.11>	b. High	1,2	~~[4]~~ 3	E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10 ~~SR 3.3.1.16~~	≤ ~~[2398]~~ 2408.24 psig	≤ [2385] psig
<DOC A.12>	8 ~~9.~~ Pressurizer Water Level — High	1(g)	3	H	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≤ ~~[93.8]~~ 97.47 %	≤ [92]%
<DOC A.13>	9 ~~10.~~ Reactor Coolant Flow — Low	1					
<DOC A.14>	a. ~~Single Loop~~	~~1(h)~~	3 per loop (f)	H	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10 ~~SR 3.3.1.16~~	≥ ~~[89.2]~~ 89 %	≥ [90]%
	b. ~~Two Loops~~	~~1(i)~~	~~3 per loop~~	~~N~~	~~SR 3.3.1.1~~ ~~SR 3.3.1.7~~ ~~SR 3.3.1.10~~ ~~SR 3.3.1.16~~	~~≥ [89.2]%~~	~~≥ [90]%~~

(continued)

T.2

T.2

T.1

(a) ~~Reviewer's Note: Unit specific implementations may contain only Allowable Value depending on Setpoint Study methodology used by the unit.~~

(g) Above the P-7 (Low Power Reactor Trips Block) interlock.

(h) ~~Above the P-8 (Power Range Neutron Flux) interlock.~~

(i) ~~Above the P-7 (Low Power Reactor Trips Block) interlock and below the P-8 (Power Range Neutron Flux) interlock.~~

T.2

(f) Separate Condition entry is allowed for each loop.

Table 3.3.1-1 (page 4 of 8)
Reactor Trip System Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	TRIP SETPOINT[a]
	~~11.~~ (10) Reactor Coolant Pump (RCP) Breaker Position						
<DOC A.15>	a. Single Loop	1[k] (f)	1 per RCP	(I) ~~J~~	SR 3.3.1.14	NA	NA
<DOC A.16>	b. Two Loops	1[k] (g)	1 per RCP	(H) ~~J~~	SR 3.3.1.14	NA	NA
<DOC A.17>	~~12.~~ (11) Undervoltage RCPs (6.9 kV bus)	1[g] (e)	(1) ~~[3]~~ per bus	(H) ~~J~~	SR 3.3.1.9 SR 3.3.1.10 ~~SR 3.3.1.16~~	≥ ~~[6760]~~ V 68.37%	≥ [4830] V
<DOC A.18>	~~13.~~ (12) Underfrequency RCPs (6.9 kV bus)	1[g] (e)	(1) ~~[3]~~ per bus	(H) ~~J~~	SR 3.3.1.9 SR 3.3.1.10 ~~SR 3.3.1.16~~	≥ ~~[57.1]~~ Hz 57.22	≥ [57.5] Hz
<DOC A.19>	~~14.~~ (13) Steam Generator (SG) Water Level – Low Low	1,2	(3) ~~[4]~~ per SG[k] (k)	E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10 ~~SR 3.3.1.16~~	≥ ~~[30.6]~~% 3.54	≥ [32.3]%
<DOC A.20>	~~15.~~ (14) SG Water Level – Low	1,2	2 per SG	E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10 ~~SR 3.3.1.16~~	≥ ~~[30.4]~~% NA	≥ [32.3]%
	Coincident with Steam Flow/ Feedwater Flow Mismatch	1,2	2 per SG	E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10 ~~SR 3.3.1.16~~	≤ ~~[42.5]~~% full steam flow at RTP	≤ [40]% full steam flow at RTP

(continued)

(a) ~~Reviewer's Note: Unit specific implementations may contain only Allowable Value depending on Setpoint Study methodology used by the unit.~~

(e) ~~[g]~~ Above the P-7 (Low Power Reactor Trips Block) interlock.

(f) ~~[h]~~ Above the P-8 (Power Range Neutron Flux) interlock.

(g) ~~[i]~~ Above the P-7 (Low Power Reactor Trips Block) interlock and below the P-8 (Power Range Neutron Flux) interlock.

(k) Separate Condition entry is allowed for each SG.

Table 3.3.1-1 (page 5 of 8)
Reactor Trip System Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	TRIP SETPOINT[a]
(DOC A.21)	~~16.~~ 15 Turbine Trip – Auto-Stop	1(h)		J			
	~~a.~~ Low Fluid Oil Pressure		3		SR 3.3.1.10 SR 3.3.1.15	≥ ~~[800]~~ 1.6 psig	≥ [800] psig
	b. Turbine Stop Valve Closure	1(h)	4		SR 3.3.1.10 SR 3.3.1.15	≥ [1]% open	≥ [1]% open
(DOC A.22)	~~17.~~ 16 Safety Injection (SI) Input from Engineered Safety Feature Actuation System (ESFAS)	1,2	2 trains	K	SR 3.3.1.14	NA	NA
	~~18.~~ 17 Reactor Trip System Interlocks						
(DOC A.26)	a. Intermediate Range Neutron Flux, P-6	2(d)	2 Trains → 2	M	SR 3.3.1.11 SR 3.3.1.13	≥ ~~[5E-11]~~ 3.1 E-11 amp	≥ [1E-10] amp
(DOC A.27)	b. Low Power Reactor Trips Block, P-7	1	1 per train	N	SR 3.3.1.11 SR 3.3.1.13	NA	NA
(DOC A.28)	c. Power Range Neutron Flux, P-8	1	4	N	SR 3.3.1.11 SR 3.3.1.13	≤ ~~[52.2]~~ 50.0% RTP	≤ [48]% RTP
	d. Power Range Neutron Flux, P-9	1	4	N	SR 3.3.1.11 SR 3.3.1.13	≤ [52.2]% RTP	≤ [50]% RTP
(DOC A.29)	~~e.~~ d Power Range Neutron Flux, P-10	1,2	4	M	SR 3.3.1.11 SR 3.3.1.13 < 10% RTP	≥ ~~[7.8]~~ RTP and ≤ ~~[12.2]~~ RTP	≥ [10]% RTP
(DOC A.30)	~~f.~~ e Turbine First Stage Impulse Pressure, ~~P-13~~ P-7 Input	1	2	N	~~[SR 3.3.1.1]~~ SR 3.3.1.10 SR 3.3.1.13 < 10%	≤ ~~[12.2]~~ turbine power	≤ [10]% turbine power

(continued)

(a) Reviewer's Note: Unit specific implementations may contain only Allowable Value depending on Setpoint Study methodology used by the unit.

(d) (f) Below the P-6 (Intermediate-Range Neutron Flux) interlocks.

(h) (j) Above ~~the P-9 (Power Range Neutron Flux) interlock~~

Insert: 3.3-19-01

INSERT: 3.3-19-01

Above the P-7 (Low Power Reactor Trips Block) interlock except during turbine overspeed trip testing.

Table 3.3.1-1 (page 6 of 8)
Reactor Trip System Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	~~TRIP SETPOINT(a)~~
<DOC A.23>	~~19~~ 18. Reactor Trip Breakers (RTBs) (i)	1,2	2 trains	L ~~K~~	SR 3.3.1.4	NA	NA
		a 3(b), 4(b), 5(b)	2 trains	C	SR 3.3.1.4	NA	NA
<DOC A.24>	~~20~~ 19. Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms	1,2	1 each per RTB	O ~~M~~	SR 3.3.1.4	NA	NA
		a 3(b), 4(b), 5(b)	1 each per RTB	C	SR 3.3.1.4	NA	NA
<DOC A.25>	~~21~~ 20. Automatic Trip Logic	a 1,2	2 trains	K ~~J~~	SR 3.3.1.5	NA	NA
		3(b), 4(b), 5(b)	2 trains	C	SR 3.3.1.5	NA	NA

~~(a) Reviewer's Note: Unit specific implementations may contain only Allowable Value depending on Setpoint Study methodology used by the unit.~~

a ~~(b)~~ With ~~RTBs closed and~~ Rod Control System capable of rod withdrawal. Insert: 3.3-20-01 T.1

i ~~(f)~~ Including any reactor trip bypass breakers that are racked in and closed for bypassing an RTB.

INSERT 3.3-20-01:

~~or~~ one or more rods not fully inserted.
and

Table 3.3.1-1 (page 7 of 8)
Reactor Trip System Instrumentation

<CTS> Note 1: Overtemperature ΔT

Allowable Value

<3.2.1.β.4> The Overtemperature ΔT Function Allowable Value shall not exceed the following Trip Setpoint by more than [3.8]% of ΔT span.

$$\Delta T \frac{(1+\tau_1 s)}{(1+\tau_2 s)}\left[\frac{1}{1+\tau_3 s}\right] \le \Delta T_o \left\{K_1 - K_2 \frac{(1+\tau_4 s)}{(1+\tau_5 s)}\left[T \frac{1}{(1+\tau_6 s)} - T'\right] + K_3(P-P') - f_1(\Delta I)\right\}$$

Where: ΔT is measured RCS ΔT, °F.
ΔT_o is the indicated ΔT at RTP, °F.
s is the Laplace transform operator, sec^{-1}.
T is the measured RCS average temperature, °F.
T' is the nominal T_{avg} at RTP, ≤ [588]°F.

P is the measured pressurizer pressure, psig
P' is the nominal RCS operating pressure, ≤ [2235] psig

$K_1 \le$ [1.09] $K_2 \ge$ [0.0138]/°F $K_3 =$ [0.000671]/psig
$\tau_1 \ge$ [8] sec $\tau_2 \le$ [3] sec $\tau_3 \le$ [2] sec
$\tau_4 \ge$ [33] sec $\tau_5 \le$ [4] sec $\tau_6 \le$ [2] sec

$f_1(\Delta I) =$ $1.26\{35 + (q_t - q_b)\}$ when $q_t - q_b \le -$ [35]% RTP
0% of RTP when -[35]% RTP $< q_t - q_b \le$ [7]% RTP
$-1.05\{(q_t - q_b) - 7\}$ when $q_t - q_b >$ [7]% RTP

Where q_t and q_b are percent RTP in the upper and lower halves of the core, respectively, and $q_t + q_b$ is the total THERMAL POWER in percent RTP.

Insert: 3.3-21-01

INSERT 3.3-21-01:

$$\Delta T \leq \Delta T_o [K_1 - K_2 \{(1 + \tau_1 s)/(1 + \tau_2 s)\}(T_{avg} - T') + K_3 (P - P') - f(\Delta I)]$$

Where:

$K_1 \leq 1.285$ $K_2 = 0.0273$ $K_3 = 0.0013$

$\tau_1 \geq 25$ seconds $\tau_2 \leq 3$ seconds

ΔT_o $\leq$ Measured full power ΔT for the channel being calibrated, °F.

T_{avg} = Average Temperature for the channel being calibrated, °F (input from instrument racks)

s = Laplace transform operator, seconds^{-1}

T' = Measured full power T_{avg} for the channel being calibrated, °F

P = Pressurizer pressure, psig (input from instrument racks)

P' = 2235 psig (i.e., nominal pressurizer pressure at rated power)

K_1 is a constant which defines the overtemperature ΔT trip margin during steady state operation if the temperature, pressure, and $f(\Delta I)$ terms are zero.

K_2 is a constant which defines the dependence of the overtemperature ΔT setpoint to T_{avg}.

K_3 is a constant which defines the dependence of the overtemperature ΔT setpoint to pressurizer pressure.

ΔI = $q_t - q_b$, where q_t and q_b are the percent power in the top and bottom halves of the core respectively, and $q_t + q_b$ is total core power in percent of RTP.

$f(\Delta I)$ = 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, where q_t and q_b are defined above such that:

(a) for $q_t - q_b$ between -15.75% and +6.9%, $f(\Delta I)=0$.

(b) for each percent that the magnitude of $q_t - q_b$ exceeds +6.9%, the ΔT trip setpoint shall be automatically reduced by an equivalent of 3.333% of RTP.

(c) for each percent that the magnitude of $q_t - q_b$ is more negative than -15.75%, the ΔT trip setpoint shall be automatically reduced by an equivalent of 4.000% of RTP.

Table 3.3.1-1 (page 8 of 8)
Reactor Trip System Instrumentation

Note 2: Overpower ΔT

The Overpower ΔT Function Allowable Value shall not exceed the following Trip Setpoint by more than [3]% of ΔT span.

$$\Delta T \frac{(1+\tau_1 s)}{(1+\tau_2 s)}\left(\frac{1}{1+\tau_3 s}\right) \le \Delta T_0 \left\{K_4 - K_5 \frac{\tau_1 s}{1+\tau_1 s}\left(\frac{1}{1+\tau_6 s}\right) T - K_6 \left[T \frac{1}{1+\tau_6 s} - T''\right] - f_2(\Delta I)\right\}$$

Where: ΔT is measured RCS ΔT, °F.
ΔT_0 is the indicated ΔT at RTP, °F.
s is the Laplace transform operator, sec^{-1}.
T is the measured RCS average temperature, °F.
T'' is the nominal T_{avg} at RTP, ≤ [588]°F.

$K_4 \le [1.09]$ $K_5 \ge [0.02]$/°F for increasing T_{avg} $K_6 \ge [0.00128]$/°F when $T > T''$
[0]/°F for decreasing T_{avg} [0]/°F when $T \le T''$
$\tau_1 \ge [8]$ sec $\tau_2 \le [3]$ sec $\tau_3 \le [2]$ sec
$\tau_6 \le [2]$ sec $\tau_7 \ge [10]$ sec

$f_2(\Delta I) = 0\%$ RTP for all ΔI.

Insert: 3.3-22-01

INSERT 3.3-22-01:

$$\Delta T \leq \Delta T_o (K_4 - K_5 (dTavg/dt) - K_6(T_{avg} - T'))$$

Where:

$K_4 \leq 1.154$

$K_5 = 0$ for decreasing average temperature; and
≥ 0.175 sec/°F for increasing average temperature

$K_6 = 0$ for $T \leq T'$; and
≥ 0.00134 for $T > T'$

$\Delta T_o \leq$ measured full power ΔT for the channel being calibrated, °F

T_{avg} = measured average temperature for the channel being calibrated, °F (input from instrument racks)

T' = measured full power T_{avg} for the channel being calibrated, °F (can be set no higher than 570.3 °F)

K_4 is a constant which defines the overpower ΔT trip margin during steady state operation if the temperature term is zero.

K_5 is a constant determined by dynamic considerations to compensate for piping delays from the core to the loop temperature detectors; it represents the combination of the equipment static gain setting and the time constant setting.

K_6 is a constant which defines the dependence of the overpower ΔT setpoint to T_{avg}.

dTavg/dt is the rate of change of T_{avg}

Protection System (RPS) (all locations)

B 3.3 INSTRUMENTATION

B 3.3.1 Reactor ~~Trip System (RTS)~~ Instrumentation

RPS Typical

BASES

BACKGROUND

The RTS initiates a unit shutdown, based on the values of selected unit parameters, to protect against violating the core fuel design limits and Reactor Coolant System (RCS) pressure boundary during anticipated operational occurrences (AOOs) and to assist the Engineered Safety Features (ESF) Systems in mitigating accidents.

The protection and monitoring systems have been designed to assure safe operation of the reactor. This is achieved by specifying limiting safety system settings (LSSS) in terms of parameters directly monitored by the RTS, as well as specifying LCOs on other reactor system parameters and equipment performance.

Allowable Value

The LSSS, defined in this specification as the ~~Trip~~ Setpoints, in conjunction with the LCOs, establish the threshold for protective system action to prevent exceeding acceptable limits during Design Basis Accidents (DBAs).

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

2735 psig

3. The RCS pressure SL of ~~2750 psia~~ 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 100 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 an acceptable fraction of 10 CFR 100 limits. Different accident categories are allowed a

(continued)

BASES

BACKGROUND (continued)

different fraction of these limits, based on probability of occurrence. Meeting the acceptable dose limit for an accident category is considered having acceptable consequences for that event.

The RTS instrumentation is as described in segmented into four distinct but interconnected modules as ~~illustrated in Figure [ ]~~, FSAR, Chapter ~~[7]~~ (Ref. 1), and as identified below:

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. RTS automatic initiation relay logic ~~Solid State Protection System (SSPS)~~, including input, logic, and output ~~bays~~: initiates proper unit 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: provides 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.

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. To account for the calibration tolerances and instrument drift, which are assumed to occur between calibrations, statistical allowances are provided in the ~~Trip Setpoint and~~ Allowable

(continued)

BASES

BACKGROUND

Field Transmitters or Sensors (continued)

Values. The OPERABILITY of each transmitter or sensor can be evaluated when its "as found" calibration data are compared against its documented ~~acceptance criteria~~.

allowable value

Signal Process Control and Protection System

Generally, three or four channels of process control equipment are used for the signal processing of unit parameters measured by the field instruments. The process control equipment provides signal conditioning, comparable output signals for instruments located on the main control board, and comparison of measured input signals with setpoints established ~~by safety analyses. These setpoints are defined in FSAR, Chapter [7] (Ref. 1), Chapter [6] (Ref. 2), and Chapter [15] (Ref. 3).~~ If the measured value of a unit parameter exceeds the predetermined setpoint, an output from a bistable is forwarded to the ~~SSPS for decision evaluation~~. Channel separation is maintained up to and through the ~~input bays~~. However, not all unit parameters require four channels of sensor measurement and signal processing. Some unit parameters provide input only to the ~~SSPS~~, while others provide input to the ~~SSPS~~, the main control board, the unit computer, and one or more control systems.

to ensure that actuation will occur within the limits assumed in the accident analysis (Ref. 3).

RPS relay logic

the actuation logic

Generally, if a parameter is used only for input to the protection circuits, three channels with a two-out-of-three logic are sufficient to provide the required reliability and redundancy. If one channel fails in a direction that would not result in a partial Function trip, the Function is still OPERABLE with a two-out-of-two logic. If one channel fails, such that a partial Function trip occurs, a trip will not occur and the Function is still OPERABLE with a one-out-of-two logic.

RPS relay logic

Generally, if a parameter is used for input to the ~~SSPS~~ and a control function, four channels with a two-out-of-four logic are sufficient to provide the required reliability and redundancy. The circuit must be able to withstand both an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Again, a single failure will neither cause nor

(continued)

BASES

BACKGROUND

Signal Process Control and Protection System (continued)

prevent the protection function actuation. These requirements are described in IEEE-279-1971 (Ref. 4). The actual number of channels required for each unit parameter is specified in Reference 1.

1968

and discussed later in these Technical Specification Bases

Two logic channels are required to ensure no single random failure of a logic channel will disable the RTS. The logic channels are designed such that testing required while the reactor is at power may be accomplished without causing trip. Provisions to allow removing logic channels from service during maintenance are unnecessary because of the logic system's designed reliability.

Trip Setpoints and Allowable Values

Insert: B3.3-4-01

The Trip Setpoints are the nominal values at which the bistables are set. Any bistable is considered to be properly adjusted when the "as left" value is within the band for CHANNEL CALIBRATION accuracy (i.e., ± rack calibration + comparator setting accuracy).

The Trip Setpoints used in the bistables are based on the analytical limits stated in Reference 1. The selection of these Trip Setpoints is such that adequate protection is provided when all sensor and processing time delays are taken into account. To allow for calibration tolerances, instrumentation uncertainties, instrument drift, and severe environment errors for those RTS channels that must function in harsh environments as defined by 10 CFR 50.49 (Ref. 5), the Trip Setpoints and Allowable Values specified in Table 3.3.1-1 in the accompanying LCO are conservatively adjusted with respect to the analytical limits. A detailed description of the methodology used to calculate the Trip Setpoints, including their explicit uncertainties, is provided in the "RTS/ESFAS Setpoint Methodology Study" (Ref. 6). The actual nominal Trip Setpoint entered into the bistable is more conservative than that specified by the Allowable Value to account for changes in random measurement errors detectable by a COT. One example of such a change in measurement error is drift during the surveillance interval. If the measured setpoint does not exceed the Allowable Value, the bistable is considered OPERABLE.

(continued)

INSERT B 3.3-4-01:

The following describes the relationship between the safety limit, analytical limit, allowable value and channel component calibration acceptance criteria:

a. A Safety Limit (SL) is a limit on the combination of THERMAL POWER, RCS highest loop average temperature, and RCS pressure needed to protect the integrity of physical barriers that guard against the uncontrolled release of radioactivity (i.e., fuel, fuel cladding, RCS pressure boundary and containment). The safety limits are identified in Technical Specification 2.0, Safety Limits (SLs).

b. An Analytical Limit (AL) is the trip actuation point used as an input to the accident analyses presented in FSAR, Chapter 14 (Ref. 3). Analytical limits are developed from event analyses models which consider parameters such as process delays, rod insertion times, reactivity changes, instrument response times, etc. An analytical limit for a trip actuation point is established at a point that will ensure that a Safety Limit (SL) is not exceeded.

c. An Allowable Value (AV) is the limiting actuation point for the entire channel of a trip function that will ensure, within the required level of confidence, that sufficient allocation exists between this actual trip function actuation point and the analytical limit. The Allowable Value is more conservative than the Analytical Limit to account for instrument uncertainties that either are not present or are not measured during periodic testing. Channel uncertainties that either are not present or are not measured during periodic testing may include design basis accident temperature and radiation effects (Ref. 5) or process dependent effects. The channel allowable value for each RPS function is controlled by Technical Specifications and is listed in Table 3.3.1-1, Reactor Protection System Instrumentation.

d. Calibration acceptance criteria (i.e., setpoints) are established by plant administrative programs for the components of a channel (i.e., required sensor, alarm, interlock, display, and trip function). The calibration acceptance criteria are established to ensure, within the required level of confidence, that the Allowable Value for the entire channel will not be exceeded during the calibration interval.

A description of the methodology used to calculate the channel allowable values and calibration acceptance criteria is provided in References 6 and 8.

BASES

BACKGROUND

Trip Setpoints and Allowable Values (continued)

Setpoints in accordance with the Allowable Value ensure that SLs are not violated during AOOs (and that the consequences of DBAs will be acceptable, providing the unit is operated from within the LCOs at the onset of the AOO or DBA and the equipment functions as designed). Note that in the accompanying LCO 3.3.1, the Trip Setpoints of Table 3.3.1-1 are the LSSS.

Relay logic protection system

Each channel of the process control equipment can be tested on line to verify that the signal or setpoint accuracy is within the specified allowance requirements of Reference 2. Once a designated channel is taken out of service for testing, a simulated signal is injected in place of the field instrument signal. The process equipment for the channel in test is then tested, verified, and calibrated. SRs for the channels are specified in the SRs section.

Insert: B 3.3-5-01

The Trip Setpoints and Allowable Values listed in Table 3.3.1-1 are based on the methodology described in Reference 6, which incorporates all of the known uncertainties applicable for each channel. The magnitudes of these uncertainties are factored into the determination of each Trip Setpoint. All field sensors and signal processing equipment for these channels are assumed to operate within the allowances of these uncertainty magnitudes.

Insert: B 3.3-5-02

Relay Logic

Solid State Protection System

Relay logic

The SSPS equipment is used for the decision logic processing of outputs from the signal processing equipment bistables. To meet the redundancy requirements, two trains of SSPS, each performing the same functions, are provided. If one train is taken out of service for maintenance or test purposes, the second train will provide reactor trip and/or ESF actuation for the unit. If both trains are taken out of service or placed in test, a reactor trip will result. Each train is packaged in its own cabinet for physical and electrical separation to satisfy separation and independence requirements. The system has been designed to trip in the event of a loss of power, directing the unit to a safe shutdown condition.

(continued)

INSERT B 3.3-5-01:

calculations performed in accordance with Reference 6 that are based on analytical limits consistent with Reference 3.

INSERT B 3.3-5-02:

and the Trip Setpoints calculated to ensure that Allowable Values are not exceeded during the calibration interval

BASES

BACKGROUND

Solid State Protection System (continued)

Relay Logic

The SSPS performs the decision logic for actuating a reactor trip or ESF actuation, generates the electrical output signal that will initiate the required trip or actuation, and provides the status, permissive, and annunciator output signals to the ~~main~~ control room ~~of the unit~~.

The bistable outputs from the signal processing equipment are sensed by the SSPS equipment and combined into logic matrices that represent combinations indicative of various unit upset and accident transients. If a required logic matrix combination is completed, the system will initiate a reactor trip or send actuation signals via master and slave relays to those components whose aggregate Function best serves to alleviate the condition and restore the unit to a safe condition. Examples are given in the Applicable Safety Analyses, LCO, and Applicability sections of this Bases.

Reactor Trip Switchgear — Breakers

Reactor protection system

The RTBs are in the electrical power supply line from the control rod drive motor generator set power supply to the CRDMs. Opening of the RTBs interrupts power to the CRDMs, which allows the shutdown rods and control rods to fall into the core by gravity. Each RTB is equipped with a bypass breaker to allow testing of the RTB while the unit is at power. During normal operation the output from the SSPS is a voltage signal that energizes the undervoltage coils in the RTBs and bypass breakers, if in use. When the required logic matrix combination is completed, the SSPS output voltage signal is removed, the undervoltage coils are de-energized, the breaker trip lever is actuated by the de-energized undervoltage coil, and the RTBs and bypass breakers are tripped open. This allows the shutdown rods and control rods to fall into the core. In addition to the de-energization of the undervoltage coils, each breaker is also equipped with a shunt trip device that is energized to trip the breaker open upon receipt of a reactor trip signal from the SSPS. Either the undervoltage coil or the shunt trip mechanism is sufficient by itself, thus providing a diverse trip mechanism.

Insert: B3.3-6-01

RPS

The decision logic ~~matrix~~ Functions are described in the functional diagrams included in Reference 2. In addition to

(continued)

INSERT B 3.3-6-01:

There are two reactor trip breakers in series so that opening either will interrupt power to the control rod drive mechanisms (CRDMs) and allow the rod cluster control assemblies (RCCAs), or "rods, " to fall into the core and shut down the reactor. Each reactor trip breaker has a parallel reactor trip bypass breaker that is normally open. This feature allows testing of the reactor trip breakers at power. A trip signal from RPS logic train A will trip reactor trip breaker A and reactor trip bypass breaker B; and, a trip signal from logic train B will trip reactor trip breaker B and reactor trip bypass breaker A. During normal operation, both reactor trip breakers are closed and both reactor trip bypass breakers are open. An interlock trips both reactor trip bypass breakers if an attempt is made to close a reactor trip bypass breaker when the other reactor trip bypass breaker is already closed.

A trip breaker train consists of both the reactor trip breaker and reactor trip bypass breaker associated with a single RPS logic train if the breaker is racked in, closed, and capable of supplying power to the CRD System. Thus, the train consists of the main breaker; or, the main breaker and bypass breaker associated with this same RPS logic train if both the breaker and bypass are racked in, closed, and capable of supplying power to the CRD System.

BASES

BACKGROUND

Reactor Trip Switchgear (continued)

protection of ESFAS trips

the reactor trip or ESF. These diagrams also describe the various "permissive interlocks" that are associated with unit conditions. Each train has a built in testing device that can automatically test the decision logic matrix Functions and the actuation devices while the unit is at power. When any one train is taken out of service for testing, the other train is capable of providing unit monitoring and protection until the testing has been completed. The testing device is semiautomatic to minimize testing time.

are described

(1)

RPS

Safety Limits (SLs)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The RTS functions to maintain the SLs during all AOOs and mitigates the consequences of DBAs in all MODES in which the RTBs are closed.

Insert: B 3.3.7-01

Abnormal Operating Occurrences (AOOs)

Each of the analyzed accidents and transients can be detected by one or more RTS Functions. The accident analysis described in Reference 3 takes credit for most RTS trip Functions. RTS trip Functions not specifically credited in the accident analysis are qualitatively credited in the safety analysis and the NRC staff approved licensing basis for the unit. These RTS trip Functions may provide protection for conditions that do not require dynamic transient analysis to demonstrate Function performance. They may also serve as backups to RTS trip Functions that were credited in the accident analysis.

The LCO requires all instrumentation performing an RTS Function, listed in Table 3.3.1-1 in the accompanying LCO, to be OPERABLE. Failure of any instrument renders the affected channel(s) inoperable and reduces the reliability of the affected Functions.

Generally,

The LCO generally requires OPERABILITY of four or three channels in each instrumentation Function, two channels of Manual Reactor Trip in each logic Function, and two trains in each Automatic Trip Logic Function. Four OPERABLE instrumentation channels in a two-out-of-four configuration are required when one RTS channel is also used as a control system input. This configuration accounts for the possibility of the shared channel failing in such a manner that it creates a transient that requires RTS action. In

Insert B 3.3-7-02

(continued)

INSERT B 3.3-7-01:

Rod Control system is capable of rod withdrawal or one or more rods not fully inserted.

INSERT B 3.3-7-02:

Isolation amplifiers prevent a control system failure from affecting the protection system (Ref. 1).

BASES

OPERABLE

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

this case, the RTS will still provide protection, even with random failure of one of the other three protection channels. Three operable instrumentation channels in a two-out-of-three configuration are generally required when there is no potential for control system and protection system interaction that could simultaneously create a need for RTS trip and disable one RTS channel. The two-out-of-three and two-out-of-four configurations allow one channel to be tripped during maintenance or testing without causing a reactor trip. Specific exceptions to the above general philosophy exist and are discussed below.

Reactor Trip System Functions

The safety analyses and OPERABILITY requirements applicable to each RTS Function are discussed below:

1. Manual Reactor Trip

push button

The Manual Reactor Trip ensures that the control room operator can initiate a reactor trip at any time by using either of two reactor trip switches in the control room. A Manual Reactor Trip accomplishes the same results as any one of the automatic trip Functions. It is used by the reactor operator to shut down the reactor whenever any parameter is rapidly trending toward its Trip Setpoint.

push button

The LCO requires two Manual Reactor Trip channels to be OPERABLE. Each channel is controlled by a manual reactor trip switch. Each channel activates the reactor trip breaker in both trains. Two independent channels are required to be OPERABLE so that no single random failure will disable the Manual Reactor Trip Function.

Rod Control

In MODE 1 or 2, manual initiation of a reactor trip must be OPERABLE. These are the MODES in which the shutdown rods and/or control rods are partially or fully withdrawn from the core. In MODE 3, 4, or 5, the manual initiation Function must also be OPERABLE if the shutdown rods or control rods are withdrawn or the Control Rod Drive (CRD) System is capable of withdrawing the shutdown rods or the control rods. In this condition, inadvertent control rod withdrawal is T.1

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1. Manual Reactor Trip (continued)

Rod Control

possible. In MODE 3, 4, or 5, manual initiation of a reactor trip does not have to be OPERABLE if the CRD System is not capable of withdrawing the shutdown rods or control rods. If the rods cannot be withdrawn from the core, there is no need to be able to trip the reactor ~~because~~ all of the rods are inserted. In MODE 6, neither the shutdown rods nor the control rods are permitted to be withdrawn and the CRDMs are disconnected from the control rods and shutdown rods. Therefore, the manual initiation Function is not required.

or

~~And~~ if all rods are fully inserted

or

T.1

2. Power Range Neutron Flux

The NIS power range detectors are located external to the reactor vessel and measure neutrons leaking from the core. The NIS power range detectors provide input to the Rod Control System and ~~the Steam Generator (SG)~~ Water Level Control System. Therefore, the actuation logic must be able to withstand an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Note that this Function also provides a signal to prevent automatic and manual rod withdrawal prior to initiating a reactor trip. Limiting further rod withdrawal may terminate the transient and eliminate the need to trip the reactor.

Turbine

Four channels of NIS are required because

three

a. Power Range Neutron Flux—High

The Power Range Neutron Flux—High trip Function ensures that protection is provided, from all power levels, against a positive reactivity excursion leading to DNB during power operations. These can be caused by rod withdrawal or reductions in RCS temperature.

Insert: B3.3-9-01

The LCO requires all four of the Power Range Neutron Flux—High channels to be OPERABLE.

In MODE 1 or 2, when a positive reactivity excursion could occur, the Power Range Neutron Flux—High trip must be OPERABLE. This Function

(continued)

INSERT B 3.3-9-01:

These channels are considered OPERABLE during required Surveillance tests that require insertion of a test signal if the channel remains untripped and capable of tripping due to an increasing neutron flux signal.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

a. Power Range Neutron Flux—High (continued)

will terminate the reactivity excursion and shut down the reactor prior to reaching a power level that could damage the fuel. In MODE 3, 4, 5, or 6, the NIS power range detectors cannot detect neutron levels in this range. In these MODES, the Power Range Neutron Flux—High does not have to be OPERABLE because the reactor is shut down and reactivity excursions into the power range are extremely unlikely. Other RTS Functions and administrative controls provide protection against reactivity additions when in MODE 3, 4, 5, or 6.

Insert: B 3.3-10-01

b. Power Range Neutron Flux—Low

The LCO requirement for the Power Range Neutron Flux—Low trip Function ensures that protection is provided against a positive reactivity excursion from low power or subcritical conditions.

The LCO requires all four of the Power Range Neutron Flux—Low channels to be OPERABLE.

In MODE 1, below the Power Range Neutron Flux (P-10 setpoint), and in MODE 2, the Power Range Neutron Flux—Low trip must be OPERABLE. This Function may be manually blocked by the operator when two out of four power range channels are greater than approximately 10% RTP (P-10 setpoint). This Function is automatically unblocked when three out of four power range channels are below the P-10 setpoint. Above the P-10 setpoint, positive reactivity additions are mitigated by the Power Range Neutron Flux—High trip Function.

In MODE 3, 4, 5, or 6, the Power Range Neutron Flux—Low trip Function does not have to be OPERABLE because the reactor is shut down and the NIS power range detectors cannot detect neutron levels in this range. Other RTS trip Functions and administrative controls provide protection

(continued)

INSERT B 3.3-10-01:

The Power Range Neutron Flux-High Allowable Value and Trip Setpoint are in accordance with Consolidated Edison Company of New York, Inc. Indian Point Nuclear Generating Station Unit No. 3 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, March 1975 (Ref. 8).

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. Power Range Neutron Flux—Low (continued)

against positive reactivity additions or power excursions in MODE 3, 4, 5, or 6.

Insert: B 3.3-11-01

3. Power Range Neutron Flux Rate

The Power Range Neutron Flux Rate trips use the same channels as discussed for Function 2 above.

a. Power Range Neutron Flux—High Positive Rate

The Power Range Neutron Flux—High Positive Rate trip Function ensures that protection is provided against rapid increases in neutron flux that are characteristic of an RCCA drive rod housing rupture and the accompanying ejection of the RCCA. This Function compliments the Power Range Neutron Flux—High and Low Setpoint trip Functions to ensure that the criteria are met for a rod ejection from the power range.

The LCO requires all four of the Power Range Neutron Flux—High Positive Rate channels to be OPERABLE.

In MODE 1 or 2, when there is a potential to add a large amount of positive reactivity from a rod ejection accident (REA), the Power Range Neutron Flux—High Positive Rate trip must be OPERABLE. In MODE 3, 4, 5, or 6, the Power Range Neutron Flux—High Positive Rate trip Function does not have to be OPERABLE because other RTS trip Functions and administrative controls will provide protection against positive reactivity additions. Also, since only the shutdown banks may be withdrawn in MODE 3, 4, or 5, the remaining complement of control bank worth ensures a sufficient degree of SDM in the event of an REA. In MODE 6, no rods are withdrawn and the SDM is increased during refueling operations. The reactor vessel head is also removed or the closure bolts are detensioned preventing any pressure buildup. In addition, the NIS power range detectors cannot detect neutron levels present in this mode.

(continued)

INSERT B 3.3-11-01:

The Power Range Neutron Flux-Low Allowable Value and Trip Setpoint are in accordance with Consolidated Edison Company of New York, Inc. Indian Point Nuclear Generating Station Unit No. 3 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, March 1975 (Ref. 8).

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

b. Power Range Neutron Flux—High Negative Rate

The Power Range Neutron Flux—High Negative Rate trip Function ensures that protection is provided for multiple rod drop accidents. At high power levels, a multiple rod drop accident could cause local flux peaking that would result in an unconservative local DNBR. DNBR is defined as the ratio of the heat flux required to cause a DNB at a particular location in the core to the local heat flux. The DNBR is indicative of the margin to DNB. No credit is taken for the operation of this Function for those rod drop accidents in which the local DNBRs will be greater than the limit.

The LCO requires all four Power Range Neutron Flux—High Negative Rate channels to be OPERABLE.

In MODE 1 or 2, when there is potential for a multiple rod drop accident to occur, the Power Range Neutron Flux—High Negative Rate trip must be OPERABLE. In MODE 3, 4, 5, or 6, the Power Range Neutron Flux—High Negative Rate trip Function does not have to be OPERABLE because the core is not critical and DNB is not a concern. Also, since only the shutdown banks may be withdrawn in MODE 3, 4, or 5, the remaining complement of control bank worth ensures a sufficient degree of SDM in the event of an REA. In MODE 6, no rods are withdrawn and the required SDM is increased during refueling operations. In addition, the NIS power range detectors cannot detect neutron levels present in this MODE.

3 ~~c~~. Intermediate Range Neutron Flux

The Intermediate Range Neutron Flux trip Function ensures that protection is provided against an uncontrolled RCCA bank rod withdrawal accident from a subcritical condition during startup. This trip Function provides redundant protection to the Power Range Neutron Flux—Low Setpoint trip Function. The NIS intermediate range detectors are located external to the reactor vessel and measure neutrons leaking from the core. The NIS intermediate range detectors

Insert: B 3.3-12-01

CLB.1

(continued)

INSERT B 3.3-12-01:

Therefore, only one of the two channels of Intermediate Range Neutron Flux is Required to be OPERABLE in the Applicable MODES. Either of the two channels can be used to satisfy this requirement.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3 ~~A~~. Intermediate Range Neutron Flux (continued)

do not provide any input to control systems. Note that this Function also provides a signal to prevent automatic and manual rod withdrawal prior to initiating a reactor trip. Limiting further rod withdrawal may terminate the transient and eliminate the need to trip the reactor.

The LCO requires two channel~~s~~ of Intermediate Range Neutron Flux to be OPERABLE. Two OPERABLE channels are sufficient to ensure no single random failure will disable this trip Function.

One

One

is

Insert: B3.3-13-01

Because this trip Function is important only during startup, there is generally no need to disable channels for testing while the Function is required to be OPERABLE. Therefore, a third channel is unnecessary.

above the P-6 setpoint

In MODE 1 below the P-10 setpoint, and in MODE 2~~,~~ when there is a potential for an uncontrolled RCCA bank rod withdrawal accident during reactor startup, the Intermediate Range Neutron Flux trip must be OPERABLE. Above the P-10 setpoint, the Power Range Neutron Flux—High Setpoint trip and the Power Range Neutron Flux—High Positive Rate trip provide core protection for a rod withdrawal accident. In MODE 3, 4, or 5, the Intermediate Range Neutron Flux trip does not have to be OPERABLE because the control rods must be fully inserted and only the shutdown rods may be withdrawn. The reactor cannot be started up in this condition. The core also has the required SDM to mitigate the consequences of a positive reactivity addition accident. In MODE 6, all rods are fully inserted and the core has a required increased SDM. Also, the NIS intermediate range detectors cannot detect neutron levels present in this MODE.

T.1

T.1

Insert: B3.3-13-02

4 ~~B~~. Source Range Neutron Flux

The LCO requirement for the Source Range Neutron Flux trip Function ensures that protection is provided against an uncontrolled RCCA bank rod withdrawal accident from a subcritical condition during startup. This trip Function provides redundant protection to

(continued)

INSERT B 3.3-13-01:

to provide redundant protection to the Power Range Neutron Flux – Low Setpoint trip Function.

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 is 25% RTP. This allowable value was established based on Indian Point Nuclear Generating Station Unit No. 3 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, March 1975, (Ref. 8).

INSERT B 3.3-13-02:

In MODE 2, below the P-6 setpoint, the source Range Neutron Flux Trip provides backup core protection for reactivity accidents.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

~~5~~ 4. Source Range Neutron Flux (continued)

Insert: B 3.3-14-01

the Power Range Neutron Flux—Low ~~Setpoint and Intermediate Range Neutron Flux~~ trip Functions. In MODES 3, 4, and 5, administrative controls also prevent the uncontrolled withdrawal of rods. The NIS source range detectors are located external to the reactor vessel and measure neutrons leaking from the core. The NIS source range detectors do not provide any inputs to control systems. The source range trip is the only RTS automatic protection function required in MODES 3, 4, and 5. Therefore, the functional capability at the specified ~~Trip Setpoint~~ Allowable Value is assumed to be available.

Insert: B 3.3-14-02

The LCO requires ~~two~~ One channel~~s~~ of Source Range Neutron Flux to be OPERABLE. ~~Two~~ One OPERABLE channel~~s~~ ~~are~~ is sufficient ~~to ensure no single random failure will disable this trip Function. The LCO also requires one channel of the Source Range Neutron Flux to be OPERABLE in MODE 3, 4, or 5 with RTBs open. In this case, the source range Function is to provide control room indication and input to the Boron Dilution Protection System (BDPS). The outputs of the Function to RTS logic are not required OPERABLE when the RTBs are open.~~

Insert: B 3.3-14-03

Insert: B 3.3-14-06

The Source Range Neutron Flux Function provides protection for control rod withdrawal from subcritical~~, boron dilution and control rod ejection events~~. The Function also provides visual neutron flux indication in the control room.

Insert B 3.3-14-04

In MODE 2 when below the P-6 setpoint ~~during a reactor startup~~, the Source Range Neutron Flux trip must be OPERABLE. Above the P-6 setpoint, the Intermediate Range Neutron Flux trip and the Power Range Neutron Flux—Low ~~Setpoint~~ trip will provide core protection for reactivity accidents. Above the P-6 setpoint, the NIS source range detectors are de-energized ~~and inoperable~~.

Insert B 3.3-14-05

In MODES 3, 4, ~~or~~ and 5 with the reactor shut down, the Source Range Neutron Flux trip Function must also be OPERABLE. If the CRD System is capable of rod withdrawal, the Source Range Neutron Flux trip must be

(continued)

INSERT B 3.3-14-01:

Therefore, only one of the two channels of Source Range Neutron Flux is Required to be OPERABLE in the Applicable MODES. Either of the two channels can be used to satisfy this requirement.

INSERT B 3.3-14-02:

when rods are capable of withdrawal or one or more rods are not fully inserted.

INSERT B 3.3-14-03:

to provide redundant protection to the Power Range Neutron Flux – Low Setpoint trip Function.

INSERT B 3.3-14-04:

and in MODES 3, 4, and 5, when there is a potential for an uncontrolled RCCA bank withdrawal accident,

INSERT B 3.3-14-05:

all rods fully inserted and the Rod Control System not capable of rod withdrawal, and in MODE 6, the outputs of this function to the RPS logic are not required to be OPERABLE.

INSERT B 3.3-14-06:

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 is 1.0 E+5 counts per second. This allowable value was established based on Indian Point Nuclear Generating Station Unit No. 3 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, March 1975, (Ref. 8).

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

4 ~~5~~. Source Range Neutron Flux (continued)

OPERABLE to provide core protection against a rod withdrawal accident. If the CRD System is not capable of rod withdrawal, the source range detectors are not required to trip the reactor. However, their monitoring Function must be OPERABLE to monitor core neutron levels and provide indication of reactivity changes that may occur as a result of events like a boron dilution. These inputs are provided to the BDPS. The requirements for the NIS source range detectors in MODE 6 are addressed in LCO 3.9.3, 2 "Nuclear Instrumentation."

~~6~~. Overtemperature ΔT

The Overtemperature ΔT trip Function is provided to ensure that the design limit DNBR is met. This trip Function also limits the range over which the Overpower ΔT trip Function must provide protection. The inputs to the Overtemperature ΔT trip include axial pressure, coolant temperature, axial power distribution, and reactor power as indicated by loop ΔT assuming full reactor coolant flow. Protection from violating the DNBR limit is assured for those transients that are slow with respect to delays from the core to the measurement system. The Function monitors both variation in power and flow since a decrease in flow has the same effect on ΔT as a power increase. The Overtemperature ΔT trip Function uses each loop's ΔT as a measure of reactor power and is compared with a setpoint that is automatically varied with the following parameters:

- reactor coolant average temperature—the Trip Setpoint is varied to correct for changes in coolant density and specific heat capacity with changes in coolant temperature;
- pressurizer pressure—the Trip Setpoint is varied to correct for changes in system pressure; and
- axial power distribution—f(ΔI), the Trip Setpoint is varied to account for imbalances in the axial power distribution as detected by the

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

5. Overtemperature ΔT (continued)

NIS upper and lower power range detectors. If axial peaks are greater than the design limit, as indicated by the difference between the upper and lower NIS power range detectors, the Trip Setpoint is reduced in accordance with Note 1 of Table 3.3.1-1.

Technical Specification

Dynamic compensation is included for system piping delays from the core to the temperature measurement system.

The Overtemperature ΔT trip Function is calculated for each loop as described in Note 1 of Table 3.3.1-1. Trip occurs if Overtemperature ΔT is indicated in two loops. At some units, the pressure and temperature signals are used for other control functions. For those units, the actuation logic must be able to withstand an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Note that this Function also provides a signal to generate a turbine runback prior to reaching the Trip Setpoint. A turbine runback will reduce turbine power and reactor power. A reduction in power will normally alleviate the Overtemperature ΔT condition and may prevent a reactor trip.

Therefore

is designed

The LCO requires all four channels of the Overtemperature ΔT trip Function to be OPERABLE for two and four loop units (the LCO requires all three channels on the Overtemperature ΔT trip Function to be OPERABLE for three loop units). Note that the Overtemperature ΔT Function receives input from channels shared with other RTS Functions. Failures that affect multiple Functions require entry into the Conditions applicable to all affected Functions.

In MODE 1 or 2, the Overtemperature ΔT trip must be OPERABLE to prevent DNB. In MODE 3, 4, 5, or 6, this trip Function does not have to be OPERABLE because the reactor is not operating and there is insufficient heat production to be concerned about DNB.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

6 7. Overpower ΔT

The Overpower ΔT trip Function ensures that protection is provided to ensure the integrity of the fuel (i.e., no fuel pellet melting and less than 1% cladding strain) under all possible overpower conditions. This trip Function also limits the required range of the Overtemperature ΔT trip Function and provides a backup to the Power Range Neutron Flux—High Setpoint trip. The Overpower ΔT trip Function ensures that the allowable heat generation rate (kW/ft) of the fuel is not exceeded. It uses the ΔT of each loop as a measure of reactor power with a setpoint that is automatically varied with the following parameters:

- reactor coolant average temperature—the Trip Setpoint is varied to correct for changes in coolant density and specific heat capacity with changes in coolant temperature; and

- rate of change of reactor coolant average temperature—including dynamic compensation for the delays between the core and the temperature measurement system.

a constant determined by dynamic considerations that provides

The Overpower ΔT trip Function is calculated for each loop as per Note 2 of Table 3.3.1-1. Trip occurs if Overpower ΔT is indicated in two loops. At some units, the temperature signals are used for other control functions. At those units, the actuation logic must be able to withstand an input failure to the control system, which may then require the protection function actuation and a single failure in the remaining channels providing the protection function actuation. Note that this Function also provides a signal to generate a turbine runback prior to reaching the Allowable Value. A turbine runback will reduce turbine power and reactor power. A reduction in power will normally alleviate the Overpower ΔT condition and may prevent a reactor trip.

Therefore,

is designed to

The LCO requires four channels for two and four loop units (three channels for three loop units) of the Overpower ΔT trip Function to be OPERABLE. Note that the Overpower ΔT trip Function receives input from

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

6. Overpower ΔT (continued)

channels shared with other RTS Functions. Failures that affect multiple Functions require entry into the Conditions applicable to all affected Functions.

In MODE 1 or 2, the Overpower ΔT trip Function must be OPERABLE. These are the only times that enough heat is generated in the fuel to be concerned about the heat generation rates and overheating of the fuel. In MODE 3, 4, 5, or 6, this trip Function does not have to be OPERABLE because the reactor is not operating and there is insufficient heat production to be concerned about fuel overheating and fuel damage.

7. Pressurizer Pressure

The same sensors provide input to the Pressurizer Pressure—High and —Low trips and the Overtemperature ΔT trip. At some units, the Pressurizer Pressure channels are also used to provide input to the Pressurizer Pressure Control System. For those units, the actuation logic must be able to withstand an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation.

a. Pressurizer Pressure—Low

The Pressurizer Pressure—Low trip Function ensures that protection is provided against violating the DNBR limit due to low pressure.

The LCO requires four channels for two and four loop units (three channels for three loop units) of Pressurizer Pressure—Low to be OPERABLE.

In MODE 1, when DNB is a major concern, the Pressurizer Pressure—Low trip must be OPERABLE. This trip Function is automatically enabled on increasing power by the P-7 interlock (NIS power range P-10 or turbine impulse pressure greater than approximately 10% of full power equivalent

(continued)

INSERT B 3.3-18-01:

Note that the plant design and this LCO require 4 channels for the Pressurizer Pressure–Low trips but requires only 3 channels of Pressurizer Pressure–High. This difference recognizes the role of pressurizer code safety valves in response to a high pressure condition.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

a. Pressurizer Pressure—Low (continued)

(P-13). On decreasing power, this trip Function is automatically blocked below P-7. Below the P-7 setpoint, no conceivable power distributions can occur that would cause DNB concerns.

b. Pressurizer Pressure—High

The Pressurizer Pressure—High trip Function ensures that protection is provided against overpressurizing the RCS. This trip Function operates in conjunction with the pressurizer relief and safety valves to prevent RCS overpressure conditions.

three

The LCO requires four channels for two and four loop units (three channels for three loop units) of the Pressurizer Pressure—High to be OPERABLE.

Allowable Value

The Pressurizer Pressure—High LSSS is selected to be below the pressurizer safety valve actuation pressure and above the power operated relief valve (PORV) setting. This setting minimizes challenges to safety valves while avoiding unnecessary reactor trip for those pressure increases that can be controlled by the PORVs.

In MODE 1 or 2, the Pressurizer Pressure—High trip must be OPERABLE to help prevent RCS overpressurization and minimize challenges to the relief and safety valves. In MODE 3, 4, 5, or 6, the Pressurizer Pressure—High trip Function does not have to be OPERABLE because transients that could cause an overpressure condition will be slow to occur. Therefore, the operator will have sufficient time to evaluate unit conditions and take corrective actions. Additionally, low temperature overpressure protection systems provide overpressure protection when below MODE 4.

Insert: B 3.3-19-01

(continued)

INSERT B 3.3-19-01:

RCS temperature is less than the LTOP arming temperature specified in LCO 3.4.12, Low Temperature Overpressure Protection (LTOP).

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

8 ~~9~~. Pressurizer Water Level—High

The Pressurizer Water Level—High trip Function provides a backup signal for the Pressurizer Pressure—High trip and also provides protection against water relief through the pressurizer safety valves. These valves are designed to pass steam in order to achieve their design energy removal rate. A reactor trip is actuated prior to the pressurizer becoming water solid. The LCO requires three channels of Pressurizer Water Level—High to be OPERABLE. The pressurizer level channels are used as input to the Pressurizer Level Control System. A fourth channel is not required to address control/protection interaction concerns. The level channels do not actuate the safety valves, and the high pressure reactor trip is set below the safety valve setting. Therefore, with the slow rate of charging available, pressure overshoot due to level channel failure cannot cause the safety valve to lift before reactor high pressure trip.

because the

In MODE 1, when there is a potential for overfilling the pressurizer, the Pressurizer Water Level—High trip must be OPERABLE. This trip Function is automatically enabled on increasing power by the P-7 interlock. On decreasing power, this trip Function is automatically blocked below P-7. Below the P-7 setpoint, transients that could raise the pressurizer water level will be slow and the operator will have sufficient time to evaluate unit conditions and take corrective actions.

9 ~~10~~. Reactor Coolant Flow—Low

a. Reactor Coolant Flow—Low (Single Loop)

The Reactor Coolant Flow—Low (Single Loop) trip Function ensures that protection is provided against violating the DNBR limit due to low flow in one or more RCS loops, while avoiding reactor trips due to normal variations in loop flow. Above the P-8 setpoint, which is approximately 48% RTP, a loss of flow in any RCS loop will actuate a reactor trip. Each RCS loop has three flow detectors to monitor flow. The flow signals are not used for any control system input.

50%

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

a. Reactor Coolant Flow—Low (Single Loop) (continued)

The LCO requires three Reactor Coolant Flow—Low channels per loop to be OPERABLE in MODE 1 above P-8.

RCS

Insert: B3.3-21-01

In MODE 1 above the P-8 setpoint, a loss of flow in one RCS loop could result in DNB conditions in the core. In MODE 1 below the P-8 setpoint, a loss of flow in two or more loops is required to actuate a reactor trip (Function ~~10.b~~ 9.b) because of the lower power level and the greater margin to the design limit DNBR. T.2

b. Reactor Coolant Flow—Low (Two Loops)

The Reactor Coolant Flow—Low (Two Loops) trip Function ensures that protection is provided against violating the DNBR limit due to low flow in two or more RCS loops while avoiding reactor trips due to normal variations in loop flow.

Above the P-7 setpoint and below the P-8 setpoint, a loss of flow in two or more loops will initiate a reactor trip. Each loop has three flow detectors to monitor flow. The flow signals are not used for any control system input.

The LCO requires three Reactor Coolant Flow—Low channels per loop to be OPERABLE.

Insert: B 3.3-21-02

In MODE 1 above the P-7 setpoint and below the P-8 setpoint, the Reactor Coolant Flow—Low (Two Loops) trip must be OPERABLE. Below the P-7 setpoint, all reactor trips on low flow are automatically blocked since no conceivable power distributions could occur that would cause a DNB concern at this low power level. Above the P-7 setpoint, the reactor trip on low flow in two or more RCS loops is automatically enabled. Above the P-8 setpoint, a loss of flow in any one loop will actuate a reactor trip because of the higher power level and the reduced margin to the design limit DNBR.

Function 9.a

(continued)

NUREG-1431 Markup Inserts
ITS SECTION 3.3.1 - REACTOR PROTECTION SYSTEM (RPS) INSTRUMENTATION

INSERT B 3.3-21-01:

Each reactor coolant loop is considered to be a separate function. Therefore, separate condition entry is allowed for each loop.

INSERT B 3.3-21-02:

Each reactor coolant loop is considered to be a separate function. Therefore, separate condition entry is allowed for each loop.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

10 ~~11.~~ Reactor Coolant Pump (RCP) Breaker Position

Both RCP Breaker Position trip Functions operate ~~together on two sets of auxiliary contacts, with one set on each RCP breaker. These Functions~~ to anticipate the Reactor Coolant Flow—Low trips to avoid RCS heatup that would occur before the low flow trip actuates.

a. Reactor Coolant Pump Breaker Position (Single Loop)

The RCP Breaker Position (Single Loop) trip Function ensures that protection is provided against violating the DNBR limit due to a loss of flow in one RCS loop. The position of each RCP breaker is monitored. If one RCP breaker is open above the P-8 setpoint, a reactor trip is initiated. This trip Function will generate a reactor trip before the Reactor Coolant Flow—Low (Single Loop) Trip Setpoint is reached.

The LCO requires one RCP Breaker Position channel per RCP to be OPERABLE. One OPERABLE channel is sufficient for this trip Function because the RCS Flow—Low trip alone provides sufficient protection of unit SLs for loss of flow events. The RCP Breaker Position trip serves only to anticipate the low flow trip, minimizing the thermal transient associated with loss of a pump.

Insert: B3.3-22-01

This Function measures only the discrete position (open or closed) of the RCP breaker, using a position switch. Therefore, the Function has no adjustable trip setpoint with which to associate an LSSS.

In MODE 1 above the P-8 setpoint, when a loss of flow in any RCS loop could result in DNB conditions in the core, the RCP Breaker Position (Single Loop) trip must be OPERABLE. In MODE 1 below the P-8 setpoint, a loss of flow in two or more loops is required to actuate a reactor trip because of the lower power level and the greater margin to the design limit DNBR.

Function 10.b

(continued)

INSERT B 3.3-22-01:

Each reactor coolant loop is considered to be a separate function. Therefore, separate condition entry is allowed for each loop.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

b. Reactor Coolant Pump Breaker Position (Two Loops)

The RCP Breaker Position (Two Loops) trip Function ensures that protection is provided against violating the DNBR limit due to a loss of flow in two or more RCS loops. The position of each RCP breaker is monitored. Above the P-7 setpoint ~~and below the P-8 setpoint~~, a loss of flow in two or more loops will initiate a reactor trip. This trip Function will generate a reactor trip before the Reactor Coolant Flow—Low (Two Loops) Trip Setpoint is reached.

The LCO requires one RCP Breaker Position channel per RCP to be OPERABLE. One OPERABLE channel is sufficient for this Function because the RCS Flow—Low trip alone provides sufficient protection of unit SLs for loss of flow events. The RCP Breaker Position trip serves only to anticipate the low flow trip, minimizing the thermal transient associated with loss of an RCP.

Insert B 3.3-23-01

This Function measures only the discrete position (open or closed) of the RCP breaker, using a position switch. Therefore, the Function has no adjustable trip setpoint with which to associate an LSSS.

In MODE 1 above the P-7 setpoint and below the P-8 setpoint, the RCP Breaker Position (Two Loops) trip must be OPERABLE. Below the P-7 setpoint, all reactor trips on loss of flow are automatically blocked since no conceivable power distributions could occur that would cause a DNB concern at this low power level. Above the P-7 setpoint, the reactor trip on loss of flow in two RCS loops is automatically enabled. Above the P-8 setpoint, a loss of flow in any one loop will actuate a reactor trip because of the higher power level and the reduced margin to the design limit DNBR.

Function 10.a

(continued)

INSERT B 3.3-23-01:

Each reactor coolant loop is considered to be a separate function. Therefore, separate condition entry is allowed for each loop.

BASES

(6.9 kV Bus)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

(11) ~~12~~. Undervoltage Reactor Coolant Pumps

The Undervoltage RCPs reactor trip Function ensures that protection is provided against violating the DNBR limit due to a loss of flow in two or more RCS loops. The voltage to each RCP is monitored. Above the P-7 setpoint, a loss of voltage detected on two or more RCP buses will initiate a reactor trip. This trip Function will generate a reactor trip before the Reactor Coolant Flow—Low (Two Loops) Trip Setpoint is reached. Time delays are incorporated into the Undervoltage RCPs channels to prevent reactor trips due to momentary electrical power transients.

direct

6.9 kV bus used to power an

direct

associated with the direct reactor trip are provided

The LCO requires ~~three~~ one Undervoltage RCPs channel~~s~~ ~~(one per phase)~~ per bus to be OPERABLE.

In MODE 1 above the P-7 setpoint, the Undervoltage RCP trip must be OPERABLE. Below the P-7 setpoint, all reactor trips on loss of flow are automatically blocked since no conceivable power distributions could occur that would cause a DNB concern at this low power level. Above the P-7 setpoint, the reactor trip on loss of flow in two or more RCS loops is automatically enabled. ~~This Function uses the same delays as the ESFAS Function 6.f, "Undervoltage Reactor Coolant Pump (RCP)" start of the auxiliary feedwater (AFW) pumps.~~

(12) ~~13~~. Underfrequency Reactor Coolant Pumps

The Underfrequency RCPs reactor trip Function ensures that protection is provided against violating the DNBR limit due to a loss of flow in two or more RCS loops from a major network frequency disturbance. An underfrequency condition will slow down the pumps, thereby reducing their coastdown time following a pump trip. The proper coastdown time is required so that reactor heat can be removed immediately after reactor trip. The frequency of each RCP bus is monitored. ~~Above the P-7 setpoint,~~ A loss of frequency detected on two or more RCP buses will initiate a reactor trip. This trip Function will generate a reactor trip before the Reactor Coolant Flow—Low (Two Loops) Trip Setpoint is reached. ~~Time delays are incorporated into the Underfrequency RCPs channels to prevent reactor trips due to momentary electrical power transients.~~

trips all four RCPs, a condition that

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

12 ~~13~~. Underfrequency Reactor Coolant Pumps (continued)

The LCO requires three Underfrequency RCP~~s~~ channel~~s~~ per bus to be OPERABLE.

One

In MODE 1 above the P-7 setpoint, the Underfrequency RCPs trip must be OPERABLE. Below the P-7 setpoint, all reactor trips on loss of flow are automatically blocked since no conceivable power distributions could occur that would cause a DNB concern at this low power level. Above the P-7 setpoint, the reactor trip on loss of flow in two or more RCS loops is automatically enabled.

13 ~~14~~. Steam Generator Water Level—Low Low

The SG Water Level—Low Low trip Function ensures that protection is provided against a loss of heat sink and actuates the AFW System prior to uncovering the SG tubes. The SGs are the heat sink for the reactor. In order to act as a heat sink, the SGs must contain a minimum amount of water. A narrow range low low level in any SG is indicative of a loss of heat sink for the reactor. The level transmitters provide input to the SG Level Control System. Therefore, the actuation logic must be able to withstand an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. This Function also performs the ~~ESFAS~~ function of starting the AFW pumps on low low SG level.

"B" channel

three

The LCO requires four channels of SG Water Level—Low Low per SG to be OPERABLE for four loop units in which these channels are shared between protection and control. In two, three, and four loop units where three SG Water Levels are dedicated to the RTS, only three channels per SG are required to be OPERABLE.

In MODE 1 or 2, when the reactor requires a heat sink, the SG Water Level—Low Low trip must be OPERABLE. The normal source of water for the SGs is the Main Feedwater (MFW) System (not safety related). The MFW System is only in operation in MODE 1 or 2. The AFW System is the safety related backup source of water to

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

13 ~~14~~. Steam Generator Water Level—Low Low (continued)

ensure that the SGs remain the heat sink for the reactor. During normal startups and shutdowns, the AFW System provides feedwater to maintain SG level. In MODE 3, 4, 5, or 6, the SG Water Level—Low Low Function does not have to be OPERABLE because the MFW System is not in operation and the reactor is not ~~operating or even~~ critical. Decay heat removal is accomplished by the AFW System in MODE 3 and 4 and by the Residual Heat Removal (RHR) System in MODE 4, 5, or 6.

14 ~~15~~. Steam Generator Water Level—Low, Coincident With Steam Flow/Feedwater Flow Mismatch

SG Water Level—Low, in conjunction with the Steam Flow/Feedwater Flow Mismatch, ensures that protection is provided against a loss of heat sink and actuates the AFW System ~~prior to uncovering the SG tubes~~. In addition to a decreasing water level in the SG, the difference between feedwater flow and steam flow is evaluated to determine if feedwater flow is significantly less than steam flow. With less feedwater flow than steam flow, SG level will decrease at a rate dependent upon the magnitude of the difference in flow rates. The required logic is developed from ~~There are~~ two SG level channels and two Steam Flow/Feedwater Flow Mismatch channels per SG. One narrow range level channel ~~sensing a low level~~ coincident with ~~one~~ the associated Steam Flow/Feedwater Flow Mismatch channel for the same SG ~~sensing flow mismatch~~ (steam flow greater than feed flow) will actuate a reactor trip. This function also initiates a turbine trip if reactor power is above the P-7 setpoint.

The LCO requires two channels of SG Water Level—Low coincident with Steam Flow/Feedwater Flow Mismatch.

In MODE 1 or 2, when the reactor requires a heat sink, the SG Water Level—Low coincident with Steam Flow/Feedwater Flow Mismatch trip must be OPERABLE. The normal source of water for the SGs is the MFW System (not safety related). The MFW System is only in operation in MODE 1 or 2. The AFW System is the safety related backup source of water to ensure that the SGs remain the heat sink for the reactor. During normal startups and shutdowns, the AFW System provides feedwater to maintain SG level. In MODE 3, 4, 5,

Insert: B3.3-26-01

(continued)

INSERT B 3.3-26-01:

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 13, Steam Generator Water Level-Low Low, is used to bound the analysis for a loss of feedwater event. The allowable values required for OPERABILITY of this trip function is ≥ 3.54% for steam generator level (the same allowable value as the Steam Generator Water Level-Low Low) and ≥ 1.64 E+6 pounds per hour difference for the steam flow feed flow mismatch. These allowable values are based on engineering judgement.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

14 ~~15~~. Steam Generator Water Level—Low, Coincident With Steam Flow/Feedwater Flow Mismatch (continued)

or 6, the SG Water Level—Low coincident with Steam Flow/Feedwater Flow Mismatch Function does not have to be OPERABLE because the MFW System is not in operation and the reactor is not ~~operating or even~~ critical. Decay heat removal is accomplished by the AFW System in MODE 3 and by the RHR System in MODE 4, 5, or 6. The MFW System is in operation only in MODE 1 or 2 and, therefore, this trip Function need only be OPERABLE in these MODES.

15 ~~16~~. ~~Turbine Trip~~

Auto-Stop

~~4.~~ Turbine Trip—Low ~~Fluid~~ Oil Pressure

remove indent

The Turbine Trip—Low ~~Fluid~~ Oil Pressure trip Function anticipates the loss of heat removal capabilities of the secondary system following a turbine trip. This trip Function acts to minimize the pressure/temperature transient on the reactor. Any turbine trip from a power level below the ~~P-9~~ P-7 setpoint, approximately ~~50%~~ 10% power, will not actuate a reactor trip. Three pressure switches monitor the control oil pressure in the Turbine ~~Electrohydraulic~~ Control System. A low pressure condition sensed by two-out-of-three pressure switches will actuate a reactor trip. These pressure switches do not provide any input to the control system. The unit is designed to withstand a complete loss of load and not sustain core damage or challenge the RCS pressure limitations. Core protection is provided by the Pressurizer Pressure—High trip Function and RCS integrity is ensured by the pressurizer safety valves.

The LCO requires three channels of Turbine Trip—Low Fluid Oil Pressure to be OPERABLE in MODE 1 above ~~P-9~~ P-7.

Below the ~~P-9~~ P-7 setpoint, a turbine trip does not actuate a reactor trip. In MODE 1 (below P-7 setpoint), 2, 3, 4, 5, or 6, there is no potential for a turbine trip, that would require a reactor trip

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

Auto-Stop

Turbine Trip—Low Fluid Oil Pressure (continued)

and the Turbine Trip—Low Fluid Oil Pressure trip Function does not need to be OPERABLE.

b. Turbine Trip—Turbine Stop Valve Closure

The Turbine Trip—Turbine Stop Valve Closure trip Function anticipates the loss of heat removal capabilities of the secondary system following a turbine trip from a power level below the P-9 setpoint, approximately 50% power. This action will not actuate a reactor trip. The trip Function anticipates the loss of secondary heat removal capability that occurs when the stop valves close. Tripping the reactor in anticipation of loss of secondary heat removal acts to minimize the pressure and temperature transient on the reactor. This trip Function will not and is not required to operate in the presence of a single channel failure. The unit is designed to withstand a complete loss of load and not sustain core damage or challenge the RCS pressure limitations. Core protection is provided by the Pressurizer Pressure—High trip Function, and RCS integrity is ensured by the pressurizer safety valves. This trip Function is diverse to the Turbine Trip—Low Fluid Oil Pressure trip Function. Each turbine stop valve is equipped with one limit switch that inputs to the RTS. If all four limit switches indicate that the stop valves are all closed, a reactor trip is initiated.

The LSSS for this Function is set to assure channel trip occurs when the associated stop valve is completely closed.

The LCO requires four Turbine Trip—Turbine Stop Valve Closure channels, one per valve, to be OPERABLE in MODE 1 above P-9. All four channels must trip to cause reactor trip.

Below the P-9 setpoint, a load rejection can be accommodated by the Steam Dump System. In MODE 2, 3, 4, 5, or 6, there is no potential for

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

~~b. Turbine Trip—Turbine Stop Valve Closure (continued)~~

~~a load rejection, and the Turbine Trip—Stop Valve Closure trip Function does not need to be OPERABLE.~~

(16) ~~17.~~ Safety Injection Input from Engineered Safety Feature Actuation System

The SI Input from ESFAS ensures that if a reactor trip has not already been generated by the RTS, the ESFAS automatic actuation logic will initiate a reactor trip signal upon any signal that initiates SI. This is a condition of acceptability for the LOCA. However, other transients and accidents take credit for varying levels of ESF performance and rely upon rod insertion, except for the most reactive rod that is assumed to be fully withdrawn, to ensure reactor shutdown. Therefore, a reactor trip is initiated every time an SI signal is present.

Trip Setpoint and Allowable Values are not applicable to this Function. The SI Input is provided by relay in the ESFAS. Therefore, there is no measurement signal with which to associate an LSSS.

The LCO requires two trains of SI Input from ESFAS to be OPERABLE in MODE 1 or 2.

A reactor trip is initiated every time an SI signal is present. Therefore, this trip Function must be OPERABLE in MODE 1 or 2, when the reactor is critical, and must be shut down in the event of an accident. In MODE 3, 4, 5, or 6, the reactor is not critical, and this trip Function does not need to be OPERABLE.

(17) ~~18.~~ Reactor Trip System Interlocks

Reactor protection interlocks are provided to ensure reactor trips are in the correct configuration for the current unit status. They back up operator actions to ensure protection system Functions are not bypassed during unit conditions under which the safety analysis assumes the Functions are not bypassed. Therefore, the interlock Functions do not need to be OPERABLE

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

17 ~~18~~. Reactor Trip System Interlocks (continued)

when the associated reactor trip functions are outside the applicable MODES. These are:

a. Intermediate Range Neutron Flux, P-6

The Intermediate Range Neutron Flux, P-6 interlock is actuated when any NIS intermediate range channel goes approximately one decade above the minimum channel reading. If both channels drop below the setpoint, the permissive will automatically be defeated. The LCO requirement for the P-6 interlock ensures that the following Functions are performed:

Insert: B3.3-30-01

- on increasing power, the P-6 interlock allows the manual block of the NIS Source Range, Neutron Flux reactor trip. This prevents a premature block of the source range trip and allows the operator to ensure that the intermediate range is OPERABLE prior to leaving the source range. ~~When~~ The source range trip is blocked, the high voltage to the detectors is also removed.

by removing the

- on decreasing power, the P-6 interlock automatically energizes the NIS source range detectors and enables the NIS Source Range Neutron Flux reactor trip; and

- ~~on increasing power, the P-6 interlock provides a backup block signal to the source range flux doubling circuit. Normally, this Function is manually blocked by the control room operator during the reactor startup.~~

The LCO requires two channels of Intermediate Range Neutron Flux, P-6 interlock to be OPERABLE in MODE 2 when below the P-6 interlock setpoint.

Above the P-6 interlock setpoint, the NIS Source Range Neutron Flux reactor trip will be blocked, and this Function will no longer be necessary.

(continued)

INSERT B 3.3-30-01:

Manual defeat of the P-6 interlock can be accomplished at any time by simultaneous actuation of both Reset pushbuttons.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

a. Intermediate Range Neutron Flux, P-6 (continued)

In MODE 3, 4, 5, or 6, the P-6 interlock does not have to be OPERABLE because the NIS Source Range is providing core protection, if required.

b. Low Power Reactor Trips Block, P-7

The Low Power Reactor Trips Block, P-7 interlock is actuated by input from either the Power Range Neutron Flux, P-10, or the Turbine Impulse First Stage Pressure, ~~P-13 interlock~~. The LCO requirement for the P-7 interlock ensures that the following Functions are performed:

Insert: B 3.3-31-01

(1) on increasing power, the P-7 interlock automatically enables reactor trips on the following Functions:

- Pressurizer Pressure—Low;
- Pressurizer Water Level—High;
- Reactor Coolant Flow—Low (Two Loops);
- RCPs Breaker Open (Two Loops);
- Undervoltage RCPs; and
- ~~Underfrequency~~ RCPs Turbine Trip

These reactor trips are only required when operating above the P-7 setpoint (approximately 10% power). The reactor trips provide protection against violating the DNBR limit. Below the P-7 setpoint, the RCS is capable of providing sufficient natural circulation without any RCP running.

Insert: B 3.3-31-02

(2) on decreasing power, the P-7 interlock automatically blocks reactor trips on the following Functions:

- Pressurizer Pressure—Low;

(continued)

INSERT B 3.3-31-01:

(i.e., 2 of 4 Power Range channels increasing above the P-10 (Function 17.d) setpoint or 1 of 2 Turbine First Stage Pressure (Function 17.e) setpoint)

INSERT B 3.3-31-02:

(i.e., 3 of 4 Power Range channels decreasing below the P-10 (Function 17.d) setpoint and 2 of 2 Turbine First Stage Pressure channels decreasing below the Turbine First Stage Pressure (Function 17.e) setpoint)

BASES

APPLICABLE SAFETY, ANALYSES, LCO, and APPLICABILITY

b. Low Power Reactor Trips Block, P-7 (continued)

- Pressurizer Water Level—High;
- Reactor Coolant Flow—Low (Two Loops);
- RCP Breaker Position (Two Loops);
- Undervoltage RCPs; and
- ~~Underfrequency RCPs~~; Turbine Trip

An ~~Trip Setpoint and~~ Allowable Value are not applicable to the P-7 interlock because it is a logic Function, ~~and thus has no parameter with which to associate an LSSS~~. Insert: B3.3-32-01

The P-7 interlock is a logic Function with train and not channel identity. Therefore, the LCO requires one channel per train (i.e., two trains) of Low Power Reactor Trips Block, P-7 interlock to be OPERABLE in MODE 1.

The low power trips are blocked below the P-7 setpoint and unblocked above the P-7 setpoint. In MODE 2, 3, 4, 5, or 6, this Function does not have to be OPERABLE because the interlock performs its Function when power level drops below 10% power, which is in MODE 1.

c. Power Range Neutron Flux, P-8

The Power Range Neutron Flux, P-8 interlock is actuated at approximately 48% (50%) power as determined by ~~two-out-of-four~~ NIS power range detectors. The P-8 interlock automatically enables the Reactor Coolant Flow—Low (Single Loop) and RCP Breaker Position (Single Loop) reactor trips on low flow in one or more RCS loops ~~on increasing power~~. Insert: B3.3-32-02 The LCO requirement for this trip Function ensures that protection is provided against a loss of flow in any RCS loop that could result in DNB conditions in the core when greater than approximately 48% (50%) power. On decreasing

(continued)

INSERT B 3.3-32-01:

The Allowable Value for the P-10 interlock (Function 17.d) governs input from the Power Range instruments and the Allowable Value for the Turbine First Stage Pressure interlock (Function 17.e) governs input for turbine power.

INSERT B 3.3-32-02:

whenever at least 2 of 4 the Power Range instruments increase to above the P-8 setpoint.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

c. Power Range Neutron Flux, P-8 (continued)

power, the reactor trip on low flow in any loop is automatically blocked.

Insert: B33-33-01

The LCO requires four channels of Power Range Neutron Flux, P-8 interlock to be OPERABLE in MODE 1.

In MODE 1, a loss of flow in one RCS loop could result in DNB conditions, so the Power Range Neutron Flux, P-8 interlock must be OPERABLE. In MODE 2, 3, 4, 5, or 6, this Function does not have to be OPERABLE because the core is not producing sufficient power to be concerned about DNB conditions.

~~d. Power Range Neutron Flux, P-9~~

~~The Power Range Neutron Flux, P-9 interlock is actuated at approximately 50% power as determined by two-out-of-four NIS power range detectors. The LCO requirement for this Function ensures that the Turbine Trip—Low Fluid Oil Pressure and Turbine Trip—Turbine Stop Valve Closure reactor trips are enabled above the P-9 setpoint. Above the P-9 setpoint, a turbine trip will cause a load rejection beyond the capacity of the Steam Dump System. A reactor trip is automatically initiated on a turbine trip when it is above the P-9 setpoint, to minimize the transient on the reactor.~~

~~The LCO requires four channels of Power Range Neutron Flux, P-9 interlock to be OPERABLE in MODE 1.~~

~~In MODE 1, a turbine trip could cause a load rejection beyond the capacity of the Steam Dump System, so the Power Range Neutron Flux interlock must be OPERABLE. In MODE 2, 3, 4, 5, or 6, this Function does not have to be OPERABLE because the reactor is not at a power level sufficient to have a load rejection beyond the capacity of the Steam Dump System.~~

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

d. Power Range Neutron Flux, P-10

The Power Range Neutron Flux, P-10 interlock is actuated at approximately 10% power, as determined by two-out-of-four NIS power range detectors. If power level falls below 10% RTP on 3 of 4 channels, the nuclear instrument trips will be automatically unblocked. The LCO requirement for the P-10 interlock ensures that the following Functions are performed:

- on increasing power, the P-10 interlock allows the operator to manually block the Intermediate Range Neutron Flux reactor trip. ~~Note that blocking the reactor trip also blocks the signal to prevent automatic and manual rod withdrawal~~;
- on increasing power, the P-10 interlock allows the operator to manually block the Power Range Neutron Flux—Low reactor trip;
- on increasing power, the P-10 interlock automatically provides a backup signal to block the Source Range Neutron Flux reactor trip, ~~and also to de-energize~~ by de-energizing the NIS source range detectors;
- the P-10 interlock provides one of the two inputs to the P-7 interlock; and
- on decreasing power, the P-10 interlock automatically enables the Power Range Neutron Flux—Low reactor trip and the Intermediate Range Neutron Flux reactor trip (and rod stop).

The LCO requires four channels of Power Range Neutron Flux, P-10 interlock to be OPERABLE in MODE 1 or 2.

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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

(d) ~~f~~. Power Range Neutron Flux, P-10 (continued)

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) ~~g~~. Turbine Impulse Pressure, P-13 First Stage

The Turbine Impulse Pressure, P-13 interlock is actuated when the pressure in the first stage of the high pressure turbine is greater than approximately 10% of the rated full power pressure. 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 Impulse Pressure, P-13 interlock, to be OPERABLE in MODE 1.

P-7

The Turbine Impulse Chamber Pressure, P-13 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) ~~19~~. Reactor Trip Breakers

This trip Function applies to the RTBs exclusive of individual trip mechanisms. The LCO requires two OPERABLE trains of trip breakers. A trip breaker train consists of all trip breakers associated with a single RTS logic train that are racked in, closed, and capable of supplying power to the CRD 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 RTS trip capability. (T.1)

Rod Control

Insert: B 3.3-35-01

(continued)

INSERT B 3.3-35-01:

The LCO requires two OPERABLE trains of trip breakers. Two OPERABLE trains ensure no single random failure can disable the RPS trip capability. When a reactor trip breaker is being tested, both reactor trip breaker and the reactor trip bypass breaker associated with RPS logic train not in test are closed. In this configuration, a single failure in the RPS logic train not in test could disable RPS trip capability; therefore, limits on the duration of testing are established.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

18 ~~19~~. Reactor Trip Breakers (continued)

These trip Functions must be OPERABLE in MODE 1 or 2 when the reactor is critical. In MODE 3, 4, or 5, these RTS trip Functions must be OPERABLE when the ~~RTBs or associated bypass breakers are closed, and the CRD System is capable of rod withdrawal.~~ T.1

Insert: B 3.3-36-01

19 ~~20~~. Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms

The LCO requires both the Undervoltage and Shunt Trip Mechanisms to be OPERABLE for each RTB that is in service. The trip mechanisms are not required to be OPERABLE for trip breakers that are open, racked out, incapable of supplying power to the CRD System, or declared inoperable under Function 18 above. OPERABILITY of both trip mechanisms on each breaker ensures that no single trip mechanism failure will prevent opening any breaker on a valid signal.

Rod Control

These trip Functions must be OPERABLE in MODE 1 or 2 when the reactor is critical. In MODE 3, 4, or 5, these RTS trip Functions must be OPERABLE when the ~~RTBs and associated bypass breakers are closed, and the CRD System is capable of rod withdrawal.~~ T.1

Insert: B 3.3-36-02

20 ~~21~~. Automatic Trip Logic

The LCO requirement for the RTBs (Functions 19 and 20) and Automatic Trip Logic (Function 20) ensures that means are provided to interrupt the power to allow the rods to fall into the reactor core. Each RTB and RTBB is equipped with an undervoltage coil and a shunt trip coil to trip the breaker open when needed. Each RTB is equipped with a bypass breaker to allow testing of the trip breaker while the unit is at power. The reactor trip signals generated by the RTS Automatic Trip Logic cause the RTBs and associated bypass breakers to open and shut down the reactor.

The LCO requires two trains of RTS Automatic Trip Logic to be OPERABLE. Having two OPERABLE channels ensures that random failure of a single logic channel will not prevent reactor trip.

(continued)

INSERT B 3.3-36-01:

Rod Control System is capable of rod withdrawal ~~or~~ and one or more rods are not fully inserted.

INSERT B 3.3-36-02:

Rod Control System is capable of rod withdrawal ~~or~~ and one or more rods are not fully inserted.

BASES

APPLICABLE SAFETY ANALYSES LCO, and APPLICABILITY

21. Automatic Trip Logic (continued)

These trip Functions must be OPERABLE in MODE 1 or 2 when the reactor is critical. In MODE 3, 4, or 5, these RTS trip Functions must be OPERABLE when the RTBs ~~and associated bypass breakers are closed, and the CRD System is capable of rod withdrawal~~.

Insert: B 3.3-37-01

The RTS instrumentation satisfies Criterion 3 of ~~the NRC Policy Statement~~. 10 CFR 50.36

ACTIONS

Note 1 ~~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 3.3.1-1.

Insert: B 3.3-37-02

In the event a channel's Trip Setpoint is found nonconservative with respect to the Allowable Value, or the transmitter, instrument loop, signal processing electronics, or bistable is found inoperable, then all affected Functions provided by that channel must be declared inoperable and the LCO Condition(s) entered for the protection Function(s) affected.

When the number of inoperable channels in a trip Function exceed those specified in one or other related Conditions associated with a trip Function, then the unit is outside the safety analysis. Therefore, LCO 3.0.3 must be immediately entered if applicable in the current MODE of operation.

~~Reviewer's Note: Certain LCO Completion Times are based on approved topical reports. In order for a licensee to use these times, the licensee must justify the Completion Times as required by the staff Safety Evaluation Report (SER) for the topical report.~~

A.1

Condition A applies to all RTS protection Functions. Condition A addresses the situation where one or more required channels or trains for one or more Functions are inoperable

(continued)

NUREG-1431 Markup Inserts
ITS SECTION 3.3.1 - REACTOR PROTECTION SYSTEM (RPS) INSTRUMENTATION

INSERT B 3.3-37-01:

Rod Control System is capable of rod withdrawal ~~of~~ and one or more rods are not fully inserted.

INSERT: B 3.3-37-02

Note 2 specifies that when a channel or train is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 8 hours, provided the associated Function(s) maintains RPS trip capability. Upon completion of the Surveillance, or expiration of the 8 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is consistent with the assumptions of the instrumentation system reliability analysis (Ref. 7). That analysis demonstrated that the 8 hour testing allowance does not significantly reduce the probability that the RPS will trip when necessary.

As noted in Reference 9, the allowance of 2 hours for test and maintenance of reactor trip breakers provided in Condition L, Note 1, is less than the 6 hour allowable out of service time and the 8 hour allowance for testing of RPS train A and train B. In practice, if the reactor trip breaker is being tested at the same time as the associated logic train, the 8 hour allowance for testing of RPS train A and train B applies to both the logic train and the reactor trip breaker. This is acceptable based on the Safety Evaluation Report for Reference 7

BASES

ACTIONS

A.1 (continued)

at the same time. The Required Action is to refer to Table 3.3.1-1 and to take the Required Actions for the protection functions affected. The Completion Times are those from the referenced Conditions and Required Actions.

B.1, ~~B.2.1~~, and B.2~~.2~~

Condition B applies to the Manual Reactor Trip in MODE 1 or 2. This action addresses the train orientation of the SSPS for this Function. With one channel inoperable, the inoperable channel must be restored to OPERABLE status within 48 hours. In this Condition, the remaining OPERABLE channel is adequate to perform the safety function.

relay logic

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) ~~followed by opening the RTBs within 1 additional hour (55 hours total time)~~. The 6 additional hours to reach MODE 3 ~~and the 1 hour to open the RTBs are~~ is reasonable, based on operating experience, to reach MODE 3 ~~and open the RTBs~~ from full power operation in an orderly manner and without challenging unit systems. With the ~~RTBs open and the~~ unit in MODE 3, ~~this trip function is no longer required to be OPERABLE~~.

T.1

Insert: B 3.3-38-01

C.1 and C.2

Condition C applies to when the following reactor trip Functions in MODE 3, 4, or 5 ~~with the RTBs closed and the CRD System capable of rod withdrawal~~.

T.1

Insert: B 3.3-38-02

(continued)

INSERT B 3.3-38-01: T.1

ACTION C applies 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.

INSERT B 3.3-38-02: T.1

Rod Control System capable of rod withdrawal ~~or~~ and one or more rods are not fully inserted.

BASES

ACTIONS

C.1 and C.2 (continued)

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

relay logic

This action addresses the train orientation of the SSPS 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, the RTBs must be opened within the next hour. The additional hour provides sufficient time to accomplish the action in an orderly manner. With the RTBs open, these Functions are no longer required. T.1

Insert: B 3.3-39-01

Insert: B 3.3-39-02

The Completion Time is reasonable considering that in this Condition, the remaining OPERABLE train is adequate to perform the safety function, and given the low probability of an event occurring during this interval.

D.1.1, D.1.2, D.2.1, D.2.2, and D.3

Condition D applies to the Power Range Neutron Flux—High Function.

Rod Control

The NIS power range detectors provide input to the CRD System and the SG Water Level Control System and, therefore, have a two-out-of-four trip logic. A known inoperable channel must be placed in the tripped condition. This results in a partial trip condition requiring only one-out-of-three logic for actuation. The 6 hours allowed to place the inoperable channel in the tripped condition is justified in WCAP-10271-P-A (Ref. 7). T.1

In addition to placing the inoperable channel in the tripped condition, THERMAL POWER must be reduced to ≤ 75% RTP within 12 hours. Reducing the power level prevents operation of the core with radial power distributions beyond the design

24

(continued)

INSERT B 3.3-39-01:

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.

INSERT B 3.3-39-02:

rods fully inserted and the Rod Control System incapable of rod withdrawal.

BASES

ACTIONS

D.1.1, D.1.2, D.2.1, D.2.2, and D.3 (continued)

limits. With one of the NIS power range detectors inoperable, 1/4 of the radial power distribution monitoring capability is lost.

As an alternative to the above actions, the inoperable channel can be placed in the tripped condition within 6 hours and the QPTR monitored once every 12 hours as per SR 3.2.4.2, QPTR verification. Calculating QPTR every 12 hours compensates for the lost monitoring capability due to the inoperable NIS power range channel and allows continued unit operation at power levels > 75% RTP. The 6 hour Completion Time and the 12 hour Frequency are consistent with LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)."

As an alternative to the above Actions, the plant must be placed in a MODE where this Function is no longer required OPERABLE. Twelve hours are allowed to place the plant in MODE 3. This is a reasonable time, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging plant systems. If Required Actions cannot be completed within their allowed Completion Times, LCO 3.0.3 must be entered.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypass condition for up to 4 hours while performing routine surveillance testing of other channels. The Note also allows placing the inoperable channel in the bypass condition to allow setpoint adjustments of other channels when required to reduce the setpoint in accordance with other Technical Specifications. The 4 hour time limit is justified in Reference 7.

Required Action D.2.2 has been modified by a Note which only requires SR 3.2.4.2 to be performed if the Power Range Neutron Flux input to QPTR becomes inoperable. Failure of a component in the Power Range Neutron Flux Channel which renders the High Flux Trip Function inoperable may not affect the capability to monitor QPTR. As such, determining QPTR using this movable incore detectors once per 12 hours may not be necessary.

(continued)

BASES

ACTIONS (continued)

E.1 and E.2

Condition E applies to the following reactor trip Functions:

- Power Range Neutron Flux—Low;
- Overtemperature ΔT;
- Overpower ΔT;
- ~~Power Range Neutron Flux—High Positive Rate;~~
- ~~Power Range Neutron Flux—High Negative Rate;~~
- Pressurizer Pressure—High;
- SG Water Level—Low Low; and
- SG Water Level—Low coincident with Steam Flow/ Feedwater Flow Mismatch.

A known inoperable channel must be placed in the tripped condition within 6 hours. Placing the channel in the tripped condition results in a partial trip condition requiring only one-out-of-two logic for actuation of the two-out-of-three trips and one-out-of-three logic for actuation of the two-out-of-four trips. The 6 hours allowed to place the inoperable channel in the tripped condition is justified in Reference 7.

If the operable 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 4 hours while performing routine surveillance testing of the other channels. The 4 hour time limit is justified in Reference 7.

8

8

(continued)

BASES

ACTIONS (continued)

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, 2 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. CLB.1

F F
~~G~~.1 and ~~G~~.2 CLB.1

Condition ~~G~~ F applies when there are no to two inoperable Intermediate Range Neutron Flux trip channels OPERABLE in MODE 2 when THERMAL POWER is above the P-6 setpoint and below the P-10 setpoint. Required Actions specified in this Condition are only applicable when channel failures do not result in reactor trip. Above the P-6 setpoint and below the P-10 setpoint, the NIS intermediate range detector performs the monitoring Functions. With no intermediate range channels OPERABLE, the Required Actions are to suspend operations involving positive reactivity additions immediately. This will preclude any power level increase since there are no OPERABLE Intermediate Range Neutron Flux channels. The operator must also reduce THERMAL POWER below the P-6 setpoint within two hours. Below P-6, the one or both Source Range Neutron Flux channels will be able to monitor the core power

(continued)

BASES

ACTIONS

F F
~~G.1~~ and ~~G.2~~ (continued)

level. The Completion Time of 2 hours will allow a slow and controlled power reduction to less than the P-6 setpoint and takes into account the low probability of occurrence of an event during this period that may require the protection afforded by the NIS Intermediate Range Neutron Flux trip.

~~H.1~~

~~Condition H applies to the Intermediate Range Neutron Flux trip when THERMAL POWER is below the P-6 setpoint and one or two channels are inoperable. Below the P-6 setpoint, the NIS source range performs the monitoring and protection functions. The inoperable NIS intermediate range channel(s) must be returned to OPERABLE status prior to increasing power above the P-6 setpoint. The NIS intermediate range 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.~~ T.1

~~I.1~~

~~Condition I applies to one inoperable Source Range Neutron Flux trip channel when in MODE 2, below the P-6 setpoint, and performing a reactor startup. With the unit in this Condition, below P-6, the NIS source range performs the monitoring and protection functions. With one of the two channels inoperable, operations involving positive reactivity additions shall be suspended immediately.~~ CLB.1

~~This will preclude any power escalation. With only one source range channel OPERABLE, core protection is severely reduced and any actions that add positive reactivity to the core must be suspended immediately.~~

G ~~J.1~~ G

when there are no

OPERABLE

Condition ~~J~~ applies ~~to two inoperable~~ Source Range Neutron Flux trip channels when in MODE 2, below the P-6 setpoint, and ~~performing a reactor startup, or~~ in MODE 3, 4, or 5 with the ~~RTBs closed and the CRD System~~ capable of rod withdrawal. With the unit in this Condition, below P-6, the T.1

Rod Control

Insert: B 3.3-43-01

(continued)

INSERT B 3.3-43-01:

~~or~~ one or more rods not rods fully inserted
and

BASES

ACTIONS

G

~~J.1~~ (continued)

NIS source range performs the monitoring and protection functions. With both source range channels inoperable, the RTBs must be opened immediately. ~~With the RTBs open, the core is in a more stable condition and the unit enters Condition L.~~

~~K.1 and K.2~~

Rod Control

T.1

Insert: B 3.3-44-01

~~Condition K applies to one inoperable source range channel in MODE 3, 4, or 5 with the RTBs closed and the CRD System capable of rod withdrawal. With the unit in this Condition, below P-6, the NIS source range performs the monitoring and protection functions. With one of the source range channels inoperable, 48 hours is allowed to restore it to an OPERABLE status. If the channel cannot be returned to an OPERABLE status, 1 additional hour is allowed to open the RTBs. Once the RTBs are open, the core is in a more stable condition and the unit enters Condition L. The allowance of 48 hours to restore the channel to OPERABLE status, and the additional hour to open the RTBs are justified in Reference 7.~~

CLB.1

T.1

Insert: B 3.3-44-02

~~L.1, L.2, and L.3~~

~~Condition L applies when the required number of OPERABLE Source Range Neutron Flux channels is not met in MODE 3, 4, or 5 with the RTBs open. With the unit in this Condition, the NIS source range performs the monitoring and protection functions. With less than the required number of source range channels OPERABLE, operations involving positive reactivity additions shall be suspended immediately. This will preclude any power escalation. In addition to suspension of positive reactivity additions, all valves that could add unborated water to the RCS must be closed within 1 hour as specified in LCO 3.9.2. The isolation of unborated water sources will preclude a boron dilution accident.~~

T.1

~~Also, the SDM must be verified within 1 hour and once every 12 hours thereafter as per SR 3.1.1.1, SDM verification. With no source range channels OPERABLE, core protection is severely reduced. Verifying the SDM within 1 hour allows~~

(continued)

INSERT B 3.3-44-01:

or one or more rods not fully inserted

INSERT B 3.3-44-02:

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.

BASES

ACTIONS

~~L.1, L.2, and L.3~~ (continued)

~~sufficient time to perform the calculations and determine that the SDM requirements are met. The SDM must also be verified once per 12 hours thereafter to ensure that the core reactivity has not changed. Required Action L.1 precludes any positive reactivity additions; therefore, core reactivity should not be increasing, and a 12 hour Frequency is adequate. The Completion Times of within 1 hour and once per 12 hours are based on operating experience in performing the Required Actions and the knowledge that unit conditions will change slowly.~~ T.1

~~M.1~~ H and ~~M.2~~ H

Condition ~~M~~ H applies to the following reactor trip Functions:

- Pressurizer Pressure—Low;
- Pressurizer Water Level—High;
- Reactor Coolant Flow—Low ~~(Two Loops)~~; T.2
- RCP Breaker Position (Two Loops);
- Undervoltage RCPs; and
- Underfrequency RCPs.

With one channel inoperable, the inoperable channel must be placed in the tripped condition within 6 hours. Placing the channel in the tripped condition results in a partial trip condition requiring only one additional channel to initiate a reactor trip above the P-7 setpoint ~~and below the P-8 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. The 6 hours allowed to place the channel in the tripped condition is justified in Reference 7. 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.

Insert: B 3.3-45-01

Insert: B 3.3-45-02

Allowance of this time interval takes into consideration the redundant capability provided by the remaining redundant

(continued)

INSERT B 3.3-45-01:

for the two loop function and above the P-8 setpoint for the single loop function.

INSERT B 3.3-45-02:

The Reactor Coolant Flow-Low (Single Loop) reactor trip does not have to be OPERABLE below the P-8 setpoint; however, the Required Action must take the plant below the P-7 setpoint if the inoperable channel is not tripped within 6 hour because of the shared components between this function and the Reactor Coolant Flow-Low (Two Loop) reactor trip function.

BASES

ACTIONS

~~M~~ H.1 and ~~M~~ H.2 (continued)

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 ~~M~~ H.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to ~~4~~ 8 hours while performing routine surveillance testing of the other channels. The ~~4~~ 8 hour time limit is justified in Reference 7.

~~N.1 and N.2~~

~~Condition N applies to the Reactor Coolant Flow—Low (Single Loop) reactor trip Function. With one channel inoperable, the inoperable channel must be placed in trip within 6 hours. If the channel cannot be restored to OPERABLE status or the channel placed in trip 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 trip Function does not have to be OPERABLE below the P-8 setpoint because other RTS trip Functions provide core protection below the P-8 setpoint. The 6 hours allowed to restore the channel to OPERABLE status or place in trip and the 4 additional hours allowed to reduce THERMAL POWER to below the P-8 setpoint are justified in Reference 7.~~

~~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 7.~~

T.2

~~O~~ I.1 and ~~O~~ I.2

Condition ~~O~~ I 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.

(continued)

BASES

ACTIONS

I I
~~G~~.1 and ~~G~~.2 (continued)

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 RTS 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 7.
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 7.

8 8

J J
~~F~~.1 and ~~F~~.2 J

Auto-Stop

Condition ~~F~~ applies to Turbine Trip on Low ~~Fluid~~ Oil Pressure ~~or on Turbine Stop Valve Closure~~. With one channel inoperable, the inoperable channel must be placed in the trip condition within 6 hours. If placed in the tripped condition, this results in a partial trip condition requiring only one additional channel to initiate a reactor trip. If the channel cannot be restored to OPERABLE status or placed in the trip condition, then power must be reduced below the ~~P-9~~ setpoint within the next ~~4~~ hours. The 6 hours allowed to place the inoperable channel in the tripped condition and the ~~4~~ hours allowed for reducing power are justified in Reference 7.

P-7 6

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 7.

8

K K
~~G~~.1 and ~~G~~.2 K

Condition ~~G~~ applies to the SI Input from ESFAS reactor trip and the RTS Automatic Trip Logic in MODES 1 and 2. These actions address the train orientation of the RTS for these Functions. With one train inoperable, 6 hours are allowed to restore the train to OPERABLE status (Required Action ~~G~~.1) or the unit must be placed in MODE 3 within the

K

(continued)

BASES

ACTIONS

K K
~~J~~.1 and ~~J~~.2 (continued)

next 6 hours. The Completion Time of 6 hours (Required Action ~~J~~.1) is reasonable considering that in this Condition, the remaining OPERABLE train is adequate to perform the safety function and given the low probability of an event during this interval. The Completion Time of 6 hours (Required Action ~~J~~.2) is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems.

K

K

The Required Actions have been modified by a Note that allows bypassing one train up to ~~4~~ hours for surveillance testing, provided the other train is OPERABLE.

8

L L
~~K~~.1 and ~~K~~.2

L

Condition ~~K~~ applies to the RTBs in MODES 1 and 2. These actions address the train orientation of the RTS for the RTBs. With one train inoperable, 1 hour is allowed to restore the train to OPERABLE status or the unit must be placed in MODE 3 within the next 6 hours. 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 RTS Function. Placing the unit in MODE 3 removes the requirement for this particular Function.

Insert: B 3.3-48-01

The Required Actions have been modified by two Notes. Note 1 allows one channel to be bypassed for up to 2 hours for surveillance testing, provided the other channel is OPERABLE. Note 2 allows one RTB to be bypassed for up to 2 hours for maintenance on undervoltage or shunt trip mechanisms if the other RTB train is OPERABLE. The 2 hour time limit is justified in Reference 7.

M H
~~L~~.1 and ~~L~~.2

M

Condition ~~L~~ applies to the P-6 and P-10 interlocks. With one channel 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

or more channels

(continued)

INSERT B 3.3-48-01:

results in ACTION C entry while RTB(s) are inoperable.

BASES

ACTIONS

M M
~~S~~.1 and ~~S~~.2 (continued)

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 RTS Function.

N N
~~T~~.1 and ~~T~~.2

N or more and

and the turbine first stage input to P-7.

Condition ~~T~~ applies to the P-7, P-8, ~~P-9, and P-13~~ interlocks. With one channel 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.

O O
~~U~~.1, ~~U.2~~ 1 and U.2 ~~U~~

Condition ~~U~~ 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) ~~followed by opening the RTBs in 1 additional hour (55 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.

(continued)

BASES

ACTIONS

U.1, ~~U.2.1~~ and U.2.2 (continued)

Insert: B3.3-50-01

With the ~~RTBs open and the~~ unit in MODE 3, ~~this trip function is no longer required to be OPERABLE~~. The affected RTB shall not be bypassed while one of the diverse features is inoperable except for the time required to perform maintenance or testing 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 ~~R~~ L.

The Completion Time of 48 hours for Required Action U.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.

~~V.1~~

~~With two RTS trains inoperable, no automatic capability is available to shut down the reactor, and immediate plant shutdown in accordance with LCO 3.0.3 is required.~~

SURVEILLANCE REQUIREMENTS

The SRs for each RTS 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 RTS Functions.

Train A and Train B

Insert: B3.3-50-02

Note that each channel of process protection supplies both ~~trains~~ of the RTS. ~~When testing Channel I, Train A and Train B must be examined. Similarly, Train A and Train B must be examined when testing Channel II, Channel III, and Channel IV (if applicable).~~ The CHANNEL CALIBRATION and COTs are performed in a manner that is consistent with the assumptions used in analytically calculating the required channel accuracies.

~~Reviewer's Note: Certain Frequencies are based on approval topical reports. In order for a licensee to use these times, the licensee must justify the Frequencies as required by the staff SER for the topical report.~~

(continued)

INSERT B 3.3-50-01:

ACTION C applies to any inoperable RTB trip mechanism.

INSERT B 3.3-50-02:

When testing an individual channel, the SR is not met until both train A and train B logic are tested.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1

Performance of the CHANNEL CHECK once every 12 hours ensures that 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 3.3.1.2

SR 3.3.1.2 compares the calorimetric heat balance calculation to the NIS channel output every 24 hours. If the calorimetric exceeds the NIS channel output by > 2% RTP, the NIS is not declared inoperable, but must be adjusted. If the NIS channel output cannot be properly adjusted, the channel is declared inoperable.

Two Notes modify SR 3.3.1.2. The first Note indicates that the NIS channel output shall be adjusted consistent with the calorimetric results if the absolute difference between the NIS channel output and the calorimetric is > 2% RTP. The second Note clarifies that this Surveillance is required only if reactor power is ≥ 15% RTP and that 12 hour is

24 A

(continued)

INSERT B 3.3-52-01:

the AFD as determined by the incore detectors and the AFD as determined by the NIS channel output

INSERT B 3.3-52-02:

90% because the requirements of LCO 3.2.3, Axial Flux Difference (AFD), are relaxed significantly below 90% RTP.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.2 (continued)

allowed for performing the first Surveillance after reaching 15% RTP. At lower power levels, calorimetric data are inaccurate.

The Frequency of every 24 hours is adequate. It is based on unit operating experience, considering instrument reliability and operating history data for instrument drift. Together these factors demonstrate the change in the absolute difference between NIS and heat balance calculated powers rarely exceeds 2% in any 24 hour period.

In addition, control room operators periodically monitor redundant indications and alarms to detect deviations in channel outputs.

SR 3.3.1.3

SR 3.3.1.3 compares the incore system to the NIS channel output every 31 EFPD. If the absolute difference is ≥ 3%, the NIS channel is still OPERABLE, but must be readjusted.

If the NIS channel cannot be properly readjusted, the channel is declared inoperable. This Surveillance is performed to verify the f(ΔI) input to the overtemperature ΔT Function.

Two Notes modify SR 3.3.1.3. Note 1 indicates that the excore NIS channel shall be adjusted if the absolute difference between the incore and excore AFD is ≥ 3%. Note 2 clarifies that the Surveillance is required only if reactor power is ≥ [15%] RTP and that 24 hours is allowed for performing the first Surveillance after reaching [15%] RTP.

CLB

Insert B 3.3-52-02

The Frequency of every 31 EFPD is adequate. It is based on unit operating experience, considering instrument reliability and operating history data for instrument drift. Also, the slow changes in neutron flux during the fuel cycle can be detected during this interval.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.4

SR 3.3.1.4 is the performance of a TADOT every 31 days on a STAGGERED TEST BASIS. This test shall verify OPERABILITY by actuation of the end devices.

The RTB test shall include separate verification of the undervoltage and shunt trip mechanisms. Independent verification of RTB undervoltage and shunt trip Function is not required for the bypass breakers. No capability is provided for performing such a test at power. The independent test of the undervoltage and shunt trip function for bypass breakers is included in SR 3.3.1.14. The bypass breaker test shall include a local shunt trip. A Note has been added to indicate that this test must be performed on the bypass breaker prior to placing it in service.

The Frequency of every 31 days on a STAGGERED TEST BASIS is adequate. It is based on industry operating experience, considering instrument reliability and operating history data.

SR 3.3.1.5

SR 3.3.1.5 is the performance of an ACTUATION LOGIC TEST. The ~~SSPS~~ RPS relay logic is tested every 31 days on a STAGGERED TEST BASIS ~~using the semiautomatic tester~~. The train being tested is placed in the bypass condition, thus preventing inadvertent actuation. ~~Through the semiautomatic tester,~~ All possible logic combinations, with and without applicable permissives, are tested for each protection function required by Table 3.3.1-1. The Frequency of every 31 days on a STAGGERED TEST BASIS is adequate. It is based on industry operating experience, considering instrument reliability and operating history data.

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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.6 (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~~.

Insert B 3.3-54-01

The Frequency of 92 EFPD is adequate. ~~It is~~ based on industry operating experience, considering instrument reliability and operating history data for instrument drift.

SR 3.3.1.7

SR 3.3.1.7 is the performance of a COT every ~~[92]~~ days.

A COT is performed on each required channel to ensure the entire channel will perform the intended Function.

Setpoints must be within the Allowable Values specified in Table 3.3.1-1.

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~~.

Reference 6 which incorporates the requirements of Reference 7.

The "as found" and "as left" values must also be recorded and reviewed. ~~for consistency with the assumptions of Reference 7~~.

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.

8 hours

8

8

The Frequency of ~~[92]~~ days is justified in Reference 7.

Insert: B 3.3-54-02

(continued)

INSERT B 3.3-54-01:

90% because the requirements of LCO 3.2.3, Axial Flux Difference (AFD), are relaxed significantly below 90% RTP.

INSERT B 3.3-54-02:

The 8 hour deferral is needed because the testing required by SR 3.3.1.7 and SR 3.3.1.8 cannot be performed on the Source Range, Intermediate Range, and Power Range instruments until in the Applicable Mode and the proximity of these instruments prevents working on more than one instrument at any one time.

BASES

SURVEILLANCE REQUIREMENTS (continued)

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. The Frequency is modified by a Note that allows this surveillance to be satisfied if it has been performed within [92] 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 "4 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. The Frequency of every 92 days thereafter applies if the plant remains in the MODE of Applicability after the initial performances of prior to reactor startup and four hours after reducing power below P-10 or P-6. The MODE of Applicability for this surveillance is < P-10 for the power range low and intermediate range channels and < P-6 for the source range channels. Once the unit is in MODE 3, this surveillance is no longer required. If power is to be maintained < P-10 or < P-6 for more than 4 hours, then the testing required by this surveillance must be performed prior to the expiration of the 4 hour limit. Four hours is a reasonable time to complete the required testing or place the unit in a MODE where this surveillance is no longer required. This test ensures that the NIS source, intermediate, and power range low channels are OPERABLE prior to taking the reactor critical and after reducing power into the applicable MODE (< P-10 or < P-6) for periods > 4 hours.

16

8

Insert: B3.3-55-01

8

8 and 16 hour limits

The specified Frequency provides

within a reasonable time

Insert: B3.3-55-02

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.

(continued)

INSERT B 3.3-55-01:

Additionally, this SR must be completed for the intermediate and power range low channels within 16 hours after reducing power below the P-10 setpoint and must be completed for the source range low channel within 8 hours after reducing power below the P-6 setpoint.

INSERT B 3.3-55-02:

The deferral of the requirement to perform this test until 8 or 16 hours after entering the Applicable condition is needed because the testing required by SR 3.3.1.7 and SR 3.3.1.8 cannot be performed on the Source Range, Intermediate Range, and Power Range instruments until in the Applicable Mode and the proximity of these instruments prevents working on more than one instrument at any one time.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.9 (continued)

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

Insert: B3.3-56-01

A CHANNEL CALIBRATION is performed every [18] months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy.

used in Reference 6

CHANNEL CALIBRATIONS must be performed consistent with the assumptions of the unit specific setpoint methodology. 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.

used for

The Frequency of 18 months is based on the assumption of an 18 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.

This is needed because the

SR 3.3.1.11

24

SR 3.3.1.11 is the performance of a CHANNEL CALIBRATION, as described in SR 3.3.1.10, every 18 months. This SR is modified by a Note stating that neutron detectors are excluded from the CHANNEL CALIBRATION. The 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. The CHANNEL CALIBRATION for the source range and intermediate range neutron detectors consists of obtaining the detector

(continued)

NUREG-1431 Markup Inserts
ITS SECTION 3.3.1 - REACTOR PROTECTION SYSTEM (RPS) INSTRUMENTATION

INSERT B 3.3-56-01:

At every refueling and every 18 months for Function 11.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.11 (continued)

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 at least MODE 2 to perform the test for the intermediate range detectors and MODE 1 for the power range detectors. The [18] month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed on the [18] month Frequency.

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 [18] months. This SR is modified by a Note stating that this test shall include verification of the RCS resistance temperature detector (RTD) bypass loop flow rate.

This test will verify the rate lag compensation for flow from the core to the RTDs.

Insert B3.3-57-01

The Frequency is justified by the assumption of an [18] 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 RTS interlocks every [18] months.

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.

(continued)

INSERT B 3.3-57-01:

Whenever a sensing element is replaced, the next required CHANNEL CALIBRATION of resistance temperature detectors (RTD) sensors, which may consist of an inplace qualitative assessment of sensor behavior and normal calibration of the remaining adjustable devices in the channel, is accomplished by an inplace cross calibration that compares the other sensing elements with the recently installed element.

BASES

SURVEILLANCE REQUIREMENTS (continued)

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. This TADOT is performed every 18 months. The test shall ~~independently~~ verify the OPERABILITY of the undervoltage and shunt trip mechanisms for the Manual Reactor Trip Function for the Reactor Trip Breakers and Reactor Trip Bypass Breakers. The Reactor Trip Bypass Breaker test shall include testing of the automatic undervoltage trip.

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. The Functions affected have no setpoints associated with them.

SR 3.3.1.15

SR 3.3.1.15 is the performance of a TADOT of Turbine Trip Functions. This TADOT is as described in SR 3.3.1.4, ~~except that this test is performed prior to reactor startup. A Note states that this Surveillance is not required if it has been performed within the previous 31 days. Verification of the Trip Setpoint does not have to be performed for this Surveillance.~~ Performance of this test will ensure that the turbine trip Function is OPERABLE prior to taking the reactor critical. This test cannot be performed with the reactor at power ~~and must therefore be performed prior to reactor startup~~.

~~SR 3.3.1.16~~

~~SR 3.3.1.16 verifies that the individual channel/train actuation response times are less than or equal to the maximum values assumed in the accident analysis. Response time testing acceptance criteria are included in Technical Requirements Manual, Section 15 (Ref. 8). Individual component response times are not modeled in the analyses.~~

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.16 (continued)

The analyses model the overall or total elapsed time, from the point at which the parameter exceeds the trip setpoint value at the sensor to the point at which the equipment reaches the required functional state (i.e., control and shutdown rods fully inserted in the reactor core).

For channels that include dynamic transfer Functions (e.g., lag, lead/lag, rate/lag, etc.), the response time test may be performed with the transfer Function set to one, with the resulting measured response time compared to the appropriate FSAR response time. Alternately, the response time test can be performed with the time constants set to their nominal value, provided the required response time is analytically calculated assuming the time constants are set at their nominal values. The response time may be measured by a series of overlapping tests such that the entire response time is measured.

As appropriate, each channel's response must be verified every [18] months on a STAGGERED TEST BASIS. Testing of the final actuation devices is included in the testing. Response times cannot be determined during unit operation because equipment operation is required to measure response times. Experience has shown that these components usually pass this surveillance when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.3.1.16 is modified by a Note stating that neutron detectors are excluded from RTS RESPONSE TIME testing. This Note is necessary because of the difficulty in generating an appropriate detector input signal. Excluding the detectors is acceptable because the principles of detector operation ensure a virtually instantaneous response.

REFERENCES

1. FSAR, Chapter [7].
2. FSAR, Chapter [6].
3. FSAR, Chapter [15]. 14
4. IEEE-279-1971. 1968

(continued)

BASES

REFERENCES (continued)

5. 10 CFR 50.49.

Insert: B 3.3-60-01

6. RTS/ESFAS Setpoint Methodology Study.

7. WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.

8. Technical Requirements Manual, Section 15, "Response Times."

Insert: B 3.3-60-02

INSERT B 3.3-60-01:

6. Engineering Standards Manual IES-3B and IES-3, Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3).

INSERT B 3.3-60-02:

8. Consolidated Edison Company of New York, Inc. Indian Point Nuclear Generating Station Unit No. 3 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, March 1975.

9. WCAP14384, Implementation of RPS Technical Specification Relaxation Programs, Rev. 0, January 1996.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.1:
"Reactor Protection System (RPS) Instrumentation"

PART 6:

Justification of Differences between

NUREG-1431 and IP3 ITS

JUSTIFICATION OF DIFFERENCES FROM NUREG-1431
ITS SECTION 3.3.1 - REACTOR TRIP SYSTEM (RTS) INSTRUMENTATION

RETENTION OF EXISTING REQUIREMENT (CURRENT LICENSING BASIS)

CLB.1 NUREG-1431, Rev 1, Section 3.3.6, was modified as needed to reflect the IP3 design and current licensing basis. A detailed description of the design, accident analysis assumptions, and Operability requirements are incorporated into the IP3 ITS Bases. These changes maintain the IP3 current licensing basis except as identified and justified in the CTS/ITS discussion of changes.

PLANT-SPECIFIC WORDING PREFERENCE OR MINOR EDITORIAL IMPROVEMENT

PA.1 Corrected typographical error or made a minor editorial improvement to improve clarity and ensure requirements are fully understood and consistently applied. There are no technical changes to requirements as specified in NUREG 1431, Rev. 1; therefore, this change is not a significant or generic deviation from NUREG 1431, Rev 1.

PLANT-SPECIFIC DIFFERENCE IN THE DESIGN OR DESIGN BASIS

DB.1 Design or implementation details are incorporated or revised as necessary to more precisely describe IP3 current design or practice. These changes are intended to describe the design, improve clarity, or ensure requirements are fully understood and consistently applied. Unless identified and described blow, these changes are self-explanatory. A detailed description of the design, accident analysis assumptions, and Operability requirements are incorporated into the IP3 ITS Bases. These changes maintain the IP3 current licensing basis except as identified and justified in the CTS/ITS discussion of changes.

DIFFERENCE BASED ON A GENERIC CHANGE TRAVELER FOR NUREG-1431

T.1 This change incorporates Revision 2 of Generic Change TSTF-135 (WOG-58) which incorporates several corrections and clarifications to Required Actions for this Limiting condition for Operation.

T.2 This change incorporates Generic Change TSTF-169 (WOG-80) which combines 3.3.1, Function 10.a, Reactor Coolant Flow-Low (trip) (One Loop) and 3.3.1, Function 10.b, Reactor Coolant Flow-Low (trip) (two loop) and deletes the Required Action N.1 for LCO 3.3.1, Function 10.a. This change is needed because Action N.1 requires the channel to be tripped within 6 hours or power reduced below P-8 within 10 hours if a Reactor Coolant Flow channel is inoperable above P-8. If the channel can not be tripped, the Applicability of the two-loop trip function is entered (below P-8) and Action M.1 again requires the channel to be tripped within 6 hours or power reduced below P-7 (per M.2) in 12 hours. Since the transmitter and other loop constituents are common to both trip functions, sequential entry into N then M would allow a 22 hour AOT when only a 12 hour AOT for maintenance was evaluated in WCAP-10271 and its supplements. A 22 hour allowance is also inconsistent with the TOPS Guidelines, WOG-90-18, dated 11/1/90. This generic change to NUREG-1431, Rev 1, is approved by the NRC.

DIFFERENCE FOR ANY REASON OTHER THAN ABOVE

None

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.2:

"Engineered Safety Feature Actuation System (ESFAS) Instrumentation"

PART 1:

Indian Point 3
Improved Technical Specifications and Bases

3.3 INSTRUMENTATION

3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

LCO 3.3.2 The ESFAS instrumentation for each Function in Table 3.3.2-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.2-1.

ACTIONS

----------NOTES----------

1. Separate Condition entry is allowed for each Function.

2. When a channel or train is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 8 hours provided the associated Function maintains ESFAS trip capability.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more Functions with one or more required channels or trains inoperable.	A.1	Enter the Condition referenced in Table 3.3.2-1 for the channel(s) or train(s).	Immediately
B. One channel or train inoperable.	B.1	Restore channel or train to OPERABLE status.	48 hours
	OR		
	B.2.1	Be in MODE 3.	54 hours
	AND		
	B.2.2	Be in MODE 5.	84 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One train inoperable.	C.1 ---------NOTE--------- One train may be bypassed for up to 8 hours for surveillance testing provided the other train is OPERABLE. ---------- Restore train to OPERABLE status.	6 hours
	OR	
	C.2.1 Be in MODE 3.	12 hours
	AND	
	C.2.2 Be in MODE 5.	42 hours
D. One channel inoperable.	D.1 ---------NOTE--------- The inoperable channel may be bypassed for up to 8 hours for surveillance testing of other channels. ---------- Place channel in trip.	6 hours
	OR	
	D.2.1 Be in MODE 3.	12 hours
	AND	
	D.2.2 Be in MODE 4.	18 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. One Containment Pressure channel inoperable in one or both sets of three.	E.1 ---------NOTE--------- One additional channel may be bypassed for up to 8 hours for surveillance testing. ---------- Place channel in trip.	6 hours
	OR	
	E.2.1 Be in MODE 3.	12 hours
	AND	
	E.2.2 Be in MODE 4.	18 hours
F. One channel or train inoperable.	F.1 Restore channel or train to OPERABLE status.	48 hours
	OR	
	F.2.1 Be in MODE 3.	54 hours
	AND	
	F.2.2 Be in MODE 4.	60 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
G. One train inoperable.	G.1	---------NOTE--------- One train may be bypassed for up to 8 hours for surveillance testing provided the other train is OPERABLE. ---------- Restore train to OPERABLE status.	6 hours
	OR		
	G.2.1	Be in MODE 3.	12 hours
	AND		
	G.2.2	Be in MODE 4.	18 hours
H. One train inoperable.	H.1	---------NOTE--------- One train may be bypassed for up to 8 hours for surveillance testing provided the other train is OPERABLE. ---------- Restore train to OPERABLE status.	6 hours
	OR		
	H.2	Be in MODE 3.	12 hours

(continued)

ACTIONS (continued)

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

SURVEILLANCE REQUIREMENTS

----------NOTE----------
Refer to Table 3.3.2-1 to determine which SRs apply for each ESFAS Function.

SURVEILLANCE		FREQUENCY
SR 3.3.2.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.2.2	Perform ACTUATION LOGIC TEST.	31 days on a STAGGERED TEST BASIS
SR 3.3.2.3	Perform MASTER RELAY TEST.	31 days on a STAGGERED TEST BASIS
SR 3.3.2.4	Perform COT.	92 days
SR 3.3.2.5	Perform SLAVE RELAY TEST.	24 months
SR 3.3.2.6	----------NOTE---------- Verification of setpoint not required for manual initiation functions. --- Perform TADOT.	 24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.2.7	----------NOTE---------- This Surveillance shall include verification that the time constants are adjusted to the prescribed values. ---------- Perform CHANNEL CALIBRATION.	24 months

Table 3.3.2-1 (page 1 of 6)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Safety Injection					
a. Manual Initiation	1,2,3,4	2	B	SR 3.3.2.6	NA
b. Automatic Actuation Logic and Actuation Relays	1,2,3,4[a]	2 trains	C	SR 3.3.2.2 SR 3.3.2.3 SR 3.3.2.5	NA
c. Containment Pressure-Hi	1,2,3	3	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≤ 4.80 psig
d. Pressurizer Pressure-Low	1,2,3[b]	3	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≥ 1684.64 psig
e. High Differential Pressure Between Steam Lines	1,2,3	3 per steam line[h]	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≤ 208 psid
f. High Steam Flow in Two Steam Lines	1,2[d],3[d]	2 per steam line[h]	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	(c)
Coincident with T_{avg}- Low	1,2[d],3[d]	1 per loop[i]	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≥ 535.6°F

(continued)

(a) Only as needed to support Manual initiation capability when in MODE 4.

(b) Above the Pressurizer Pressure interlock.

(c) Less than or equal to turbine first stage pressure corresponding to 54.4% full steam flow below 20% load, and increasing linearly from 54.4% full steam flow at 20% load to 110% full steam flow at 100% load, and corresponding to 110% full steam flow above 100% load. Time delay for SI ≤ 6 seconds.

(d) Except when all MSIVs are closed.

(h) Separate Condition entry is allowed for each steam line.

(i) Separate Condition entry is allowed for each loop.

Table 3.3.2-1 (page 2 of 6)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Safety Injection (continued)					
g. High Steam Flow in Two Steam Lines	1,2[d],3[d]	2 per steam line[h]	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	(c)
Coincident with Steam Line Pressure-Low	1,2[d],3[d]	1 per steam line[h]	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≥ 476.0 psig
2. Containment Spray					
a. Manual Initiation	1,2,3,4	2 per train, 2 trains	B	SR 3.3.2.6	NA
b. Automatic Actuation Logic and Actuation Relays	1,2,3,4[a]	2 trains	C	SR 3.3.2.2 SR 3.3.2.3 SR 3.3.2.5	NA
c. Containment Pressure (Hi-Hi)	1,2,3	2 sets of 3	E	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≤ 24.3 psig

(continued)

(a) Only as needed to support Manual initiation capability when in MODE 4.

(c) Less than or equal to turbine first stage pressure corresponding to 54.4% full steam flow below 20% load, and increasing linearly from 54.4% full steam flow at 20% load to 110% full steam flow at 100% load, and corresponding to 110% full steam flow above 100% load. Time delay for SI ≤ 6 seconds.

(d) Except when all MSIVs are closed.

(h) Separate Condition entry is allowed for each steam line.

Table 3.3.2-1 (page 3 of 6)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
3. Containment Isolation					
a. Phase A Isolation					
(1) Manual Initiation	1,2,3,4	2	B	SR 3.3.2.6	NA
(2) Automatic Actuation Logic and Actuation Relays	1,2,3,4[a]	2 trains	C	SR 3.3.2.2 SR 3.3.2.3 SR 3.3.2.5	NA
(3) Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.				
b. Phase B Isolation					
(1) Manual Initiation	1,2,3,4	2	B	SR 3.3.2.6	NA
(2) Automatic Actuation Logic and Actuation Relays	1,2,3,4[a]	2 trains	C	SR 3.3.2.2 SR 3.3.2.3 SR 3.3.2.5	NA
(3) Containment Pressure (Hi- Hi)	1,2,3	2 sets of three	E	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≤ 24.3 psig

(continued)

(a) Only as needed to support Manual initiation capability when in MODE 4.

Table 3.3.2-1 (page 4 of 6)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
4. Steam Line Isolation					
a. Manual Initiation	1,2[d],3[d]	2 per steam line	F	SR 3.3.2.6	NA
b. 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
c. Containment Pressure (Hi-Hi)	1,2[d], 3[d]	2 sets of 3	E	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≤ 24.3 psig
d. High Steam Flow in Two Steam Lines	1,2[d], 3[d]	2 per steam line[h]	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	(c)
Coincident with T_{avg}-Low	1,2[d], 3[d]	1 per loop[i]	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≥ 535.6°F
e. High Steam Flow in Two Steam Lines	1,2[d], 3[d]	2 per steam line [h]	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	(c)
Coincident with Steam Line Pressure – Low	1,2[d], 3[d]	1 per steam line [i]	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≥ 476.0 psig

(continued)

(c) Less than or equal to turbine first stage pressure corresponding to 54.4% full steam flow below 20% load, and increasing linearly from 54.4% full steam flow at 20% load to 110% full steam flow at 100% load, and corresponding to 110% full steam flow above 100% load. Time delay for SI ≤ 6 seconds.

(d) Except when all MSIVs are closed.

(h) Separate Condition entry is allowed for each steam line.

(i) Separate Condition entry is allowed for each loop.

Table 3.3.2-1 (page 5 of 6)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
5. Feedwater Isolation-Safety Injection	1,2[e]	2 trains	H	SR 3.3.2.2 SR 3.3.2.5	NA
6. Auxiliary Feedwater					
a. Automatic Actuation Logic and Actuation Relays	1,2,3	2 trains	G	SR 3.3.2.2 SR 3.3.2.5	NA
b. SG Water Level-Low Low	1,2,3	3 per SG[j]	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≥ 3.54% NR
c. Safety Injection [g]	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.				
d. Loss of Offsite Power (Non SI Blackout Sequence Signal)	1,2,3	1 per bus (2 buses)	F	SR 3.3.2.6 SR 3.3.2.7	≥ 200 V
e. Trip of Main Boiler Feedwater Pumps	1[f], 2[f]	1 per MBFP	I	SR 3.3.2.6	NA

(continued)

(e) Except when all MBFPDVs, or MBFRVs and associated bypass valves are closed or isolated by a closed manual valve.

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

(g) Not required if AFW pump not required to be OPERABLE.

(j) Separate Condition entry is allowed for each SG.

Table 3.3.2-1 (page 6 of 6)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
7. ESFAS Interlocks-Pressurizer Pressure	1,2,3	3	K	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≤ 1998.24 psig

B 3.3 INSTRUMENTATION

B 3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

BASES

BACKGROUND

The ESFAS initiates necessary safety systems, based on the values of selected unit parameters, to protect against violating core design limits and the Reactor Coolant System (RCS) pressure boundary, and to mitigate accidents.

The ESFAS instrumentation is segmented into three distinct but interconnected modules as identified below:

- Field transmitters or process sensors and instrumentation: provide a measurable electronic signal based on the physical characteristics of the parameter being measured;

- Signal processing equipment including analog protection system, field contacts, and protection channel sets: provide signal conditioning, bistable setpoint comparison, process algorithm actuation, compatible electrical signal output to protection system devices, and control board/ control room/miscellaneous indications; and

- ESFAS automatic initiation relay logic: initiates the proper engineered safety feature (ESF) actuation in accordance with the defined logic and based on the bistable outputs from the signal process control and protection system.

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 ESFAS are shared with the Reactor Protection System (RPS). In some cases, the same channels also provide control system inputs. To account for calibration tolerances and instrument drift, which are assumed to occur between calibrations, statistical allowances are provided in the Trip Setpoint and Allowable Values. The OPERABILITY of each transmitter or sensor can be evaluated when its "as found"

BASES

BACKGROUND (Continued)

calibration data are compared against its documented acceptance criteria.

Signal Processing Equipment

Generally, three or four channels of process control equipment are used for the signal processing of unit parameters measured by the field instruments. The process control equipment provides signal conditioning, comparable output signals for instruments located on the main control board, and comparison of measured input signals with setpoints established by safety analyses. These setpoints are defined in FSAR, Chapter 6 (Ref. 1), Chapter 7 (Ref. 2), and Chapter 14 (Ref. 3). If the measured value of a unit parameter exceeds the predetermined setpoint, an output from a bistable is forwarded to the ESFAS relay logic for decision evaluation. Channel separation is maintained up to and through the input bays. However, not all unit parameters require four channels of sensor measurement and signal processing. Some unit parameters provide input only to the ESFAS relay logic, while others provide input to the ESFAS relay logic, the main control board, the unit computer, and one or more control systems.

Generally, if a parameter is used for input to the protection circuits only, three channels with a two-out-of-three logic are sufficient to provide the required reliability and redundancy. If one channel fails in a direction that would not result in a partial Function trip, the Function is still OPERABLE with a two-out-of-two logic. If one channel fails such that a partial Function trip occurs, a trip will not occur and the Function is still OPERABLE with a one-out-of- two logic.

Generally, if a parameter is used for input to the ESFAS relay logic and a control function, four channels with a two-out-of-four logic are sufficient to provide the required reliability and redundancy. The circuit is designed to withstand both an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function

BASES

BACKGROUND (Continued)

actuation. Again, a single failure will neither cause nor prevent the protection function actuation.

These requirements are described in IEEE-279-1968 (Ref. 4). The actual number of channels required for each unit parameter is specified in Reference 2 and discussed later in these Technical Specification Bases.

Trip Setpoints and Allowable Values

The following describes the relationship between the safety limit, analytical limit, allowable value and channel component calibration acceptance criteria:

a. A Safety Limit (SL) is a limit on the combination of THERMAL POWER, RCS highest loop average temperature, and RCS pressure needed to protect the integrity of physical barriers that guard against the uncontrolled release of radioactivity (i.e., fuel, fuel cladding, RCS pressure boundary and containment). The safety limits are identified in Technical Specification 2.0, Safety Limits (SLs).

b. An Analytical Limit (AL) is the trip actuation point used as an input to the accident analyses presented in FSAR, Chapter 14 (Ref. 3). Analytical limits are developed from event analyses models which consider parameters such as process delays, rod insertion times, reactivity changes, instrument response times, etc. An analytical limit for a trip actuation point is established at a point that will ensure that a Safety Limit (SL) is not exceeded.

c. An Allowable Value (AV) is the limiting actuation point for the entire channel of a trip function that will ensure, within the required level of confidence, that sufficient allocation exists between this actual trip function actuation point and the analytical limit. The Allowable Value is more conservative than the Analytical Limit to account for instrument uncertainties that either are not present or are not measured during periodic testing.

BASES

BACKGROUND (Continued)

Channel uncertainties that either are not present or are not measured during periodic testing may include design basis accident temperature and radiation effects (Ref. 5) or process dependent effects. The channel allowable value for each RPS function is controlled by Technical Specifications and is listed in Table 3.3.1-1, Reactor Protection System Instrumentation.

d. Calibration acceptance criteria (i.e., setpoints) are established by plant administrative programs for the components of a channel (i.e., required sensor, alarm, interlock, display, and trip function). The calibration acceptance criteria are established to ensure, within the required level of confidence, that the Allowable Value for the entire channel will not be exceeded during the calibration interval.

A description of the methodology used to calculate the channel allowable values and calibration acceptance criteria is provided in References 6 and 8.

Setpoints in accordance with the Allowable Value ensure that the consequences of Design Basis Accidents (DBAs) will be acceptable, providing the unit is operated from within the LCOs at the onset of the DBA and the equipment functions as designed.

Each channel required to be OPERABLE can be tested on line to verify that the signal processing equipment and setpoint accuracy is within the specified allowance requirements of Reference 2. Once a designated channel is taken out of service for testing, a simulated signal is injected in place of the field instrument signal. The process equipment for the channel in test is then tested, verified, and calibrated. SRs for the channels are specified in the SR section.

The Allowable Values listed in Table 3.3.2-1 and the Trip Setpoints calculated to ensure that Allowable Values are not exceeded during the calibration interval are based on the methodology described in calculations performed in accordance with Reference 6. All field sensors and signal processing

BASES

BACKGROUND (Continued)

equipment for these channels are assumed to operate within the allowances of these uncertainty magnitudes.

ESFAS Relay Logic Protection System

The relay logic equipment is used for the decision logic processing of outputs from the signal processing equipment bistables. To meet the redundancy requirements, two trains of relay logic, each performing the same functions, are provided. If one train is taken out of service for maintenance or test purposes, the second train will provide ESF actuation for the unit. Each train is packaged in a cabinet for physical and electrical separation to satisfy separation and independence requirements.

The relay logic performs the decision logic for most ESF equipment actuation; generates the electrical output signals that initiate the required actuation; and provides the status, permissive, and annunciator output signals to the main control room.

The bistable outputs from the signal processing equipment are sensed by the relay logic equipment and combined into logic that represent combinations indicative of various transients. If a required logic combination is completed, the system will send actuation signals via master and slave relays to those components whose aggregate Function best serves to alleviate the condition and restore the unit to a safe condition. Examples are given in the Applicable Safety Analyses, LCO, and Applicability sections of this Bases.

Each relay logic train has a built in testing capability that can test the decision logic matrix functions and the actuation devices while the unit is at power. When any one train is taken out of service for testing, the other train is capable of providing unit monitoring and protection until the testing has been completed.

The actuation of ESF components is accomplished through master and slave relays. The relay logic energizes the master relays

BASES

BACKGROUND (Continued)

appropriate for the condition of the unit. Each master relay then energizes one or more slave relays, which then cause actuation of the end devices. The master and slave relays are routinely tested to ensure operation.

APPLICABLE SAFETY ANALYSES,LCO, AND APPLICABILITY

Each of the analyzed accidents can be detected by one or more ESFAS Functions. One of the ESFAS Functions is the primary actuation signal for that accident. An ESFAS Function may be the primary actuation signal for more than one type of accident. An ESFAS Function may also be a secondary, or backup, actuation signal for one or more other accidents. For example, Pressurizer Pressure-Low is a primary actuation signal for small loss of coolant accidents (LOCAs) and a backup actuation signal for 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. 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.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

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. Safety Injection

Safety Injection (SI) provides two primary functions:

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).

These functions are necessary to mitigate the effects of high energy line breaks (HELBs) both inside and outside of containment. The SI signal is also used to initiate other Functions such as:

- Phase A Isolation;
- Containment Isolation;
- Reactor Trip;
- Turbine Trip;
- Feedwater Isolation;
- Start of auxiliary feedwater (AFW) pumps; and
- Control room ventilation actuation to the 10% incident mode.

These other functions ensure:

- Isolation of nonessential systems through containment penetrations;

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

- Trip of the turbine and reactor to limit power generation;
- Isolation of main feedwater (MFW) to limit secondary side mass losses;
- Start of AFW to ensure secondary side cooling capability; and
- Isolation of the control room to ensure habitability.

a. Safety Injection-Manual Initiation

The LCO requires one channel per train to be OPERABLE. The operator can initiate both trains of SI at any time by using either of two push buttons in the control room. This action will cause actuation of all components in the same manner as any of the automatic actuation signals.

The LCO for the Manual Initiation Function ensures the proper amount of redundancy is maintained in the manual ESFAS actuation circuitry to ensure the operator has manual ESFAS initiation capability.

Each channel consists of one push button and the interconnecting wiring to the actuation logic cabinet. Each push button actuates both trains. This configuration does not allow testing at power.

b. Safety Injection-Automatic Actuation Logic and Actuation Relays

This LCO requires two trains to be OPERABLE. Actuation logic consists of all circuitry within the actuation subsystems, including the initiating relay contacts responsible for actuating the ESF equipment.

Manual and automatic initiation of SI must be OPERABLE in MODES 1, 2, and 3. In these MODES, there is

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

sufficient energy in the primary and secondary systems to warrant automatic initiation of ESF systems. 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 SI, actuation is simplified by the use of the manual actuation push buttons. Automatic actuation logic and actuation relays must be OPERABLE in MODE 4 as needed to support system level manual initiation.

These Functions are not required to be OPERABLE in MODES 5 and 6 because there is adequate time for the operator to evaluate unit conditions and respond by manually starting individual systems, pumps, and other equipment to mitigate the consequences of an abnormal condition or accident. Unit pressure and temperature are very low and many ESF components are administratively locked out or otherwise prevented from actuating to prevent inadvertent overpressurization of unit systems.

c. Safety Injection-Containment Pressure-High

This signal provides protection against the following accidents:

- SLB inside containment; and
- LOCA.

Containment Pressure-High provides no input to any control functions. Thus, three OPERABLE channels are sufficient to satisfy protective requirements with a two-out-of-three logic. The transmitters (d/p cells) and electronics are located outside of containment with the sensing line (high pressure side of the transmitter) located inside containment.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Thus, the high pressure Function will not experience any adverse environmental conditions and the Trip Setpoint reflects only steady state instrument uncertainties.

Containment Pressure-High must be OPERABLE in MODES 1, 2, and 3 when there is sufficient energy in the primary and secondary systems to pressurize the containment following a pipe break. In MODES 4, 5, and 6, there is insufficient energy in the primary or secondary systems to pressurize the containment.

d. Safety Injection-Pressurizer Pressure-Low

This signal provides protection against the following accidents:

- Inadvertent opening of a steam generator (SG) relief or safety valve;
- SLB;
- Inadvertent opening of a pressurizer relief or safety valve;
- LOCAs; and
- SG Tube Rupture.

Three channels of pressurizer pressure provide input into the ESFAS actuation logic. These channels initiate the ESFAS automatically when two of the three channels exceed the low pressure setpoint. These protection channels also provide control functions; however, the two-out-of-three logic is considered adequate to provide the required protection.
The transmitters are located inside containment, with the taps in the vapor space region of the pressurizer, and thus possibly experiencing adverse environmental conditions (LOCA, SLB inside containment, rod

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

ejection). Therefore, the Trip Setpoint reflects the inclusion of both steady state and adverse environmental instrument uncertainties.

This Function must be OPERABLE in MODES 1, 2, and 3 (above the Pressurizer Pressure Interlock (Function 7) to mitigate the consequences of an HELB inside containment. This signal may be manually blocked by the operator below the Pressurizer Pressure Interlock (Function 7) setpoint. Automatic SI actuation below this pressure setpoint is performed by the Containment Pressure-High signal.

This Function is not required to be OPERABLE in MODE 3 below the Pressurizer Pressure Interlock (Funtion 8) setpoint. Other ESF functions are used to detect accident conditions and actuate the ESF systems in this MODE. In MODES 4, 5, and 6, this Function is not needed for accident detection and mitigation.

e. Safety Injection- High Differential Pressure Between Steam Lines

Steam Line Pressure – High Differential Pressure Between Steam Lines provides protection against the following accidents:

- SLB; and
- Inadvertent opening of an ADV or an SG safety valve.

High Differential Pressure Between Steam Lines provides no input to any control functions. Thus, three OPERABLE channels on each steam line are sufficient to satisfy the requirements, with a two-out-of-three logic on each steam line.

With the transmitters located inside the auxiliary feed pump room, it is possible for them to experience

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

adverse environmental conditions during a HELB event. Therefore, the Trip Setpoint reflects both steady state and adverse environmental instrument uncertainties.

Steam line high differential pressure must be OPERABLE in MODES 1, 2, and 3 when a secondary side break or stuck open valve could result in the rapid depressurization of the steam line(s). This Function is not required to be OPERABLE in MODE 4, 5, or 6 because there is not sufficient energy in the secondary side of the unit to cause an accident.

f, g. Safety Injection-High Steam Flow in Two Steam Lines Coincident With T_{avg}-Low or Coincident With Steam Line Pressure-Low

These Functions (1.f and 1.g) provide protection against the following accidents:

- SLB; and
- the inadvertent opening of a SG safety valve.

Two steam line flow channels per steam line are required OPERABLE for these Functions. The steam line flow channels are combined in a one-out-of-two logic to indicate high steam flow in one steam line. The steam flow transmitters provide control inputs, but the control function cannot cause the events that the Function must protect against. Therefore, two channels are sufficient to satisfy redundancy requirements. The one-out-of-two configuration allows online testing because trip of one high steam flow channel is not sufficient to cause initiation. High steam flow in two steam lines is acceptable in the case of a single steam line fault due to the fact that the remaining intact steam lines will pick up the full turbine load. The increased steam flow in the remaining intact lines will actuate the required

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

second high steam flow trip. Additional protection is provided by Function 1.e., High Differential Pressure Between Steam Lines.

One channel of T_{avg} per loop and one channel of low steam line pressure per steam line are required OPERABLE. For each parameter, the channels for all loops or steam lines are combined in a logic such that two channels tripped will cause a trip for the parameter. The Function trips on one-out-of-two high steam flow in any two-out-of-four steam lines if there is one-out-of-one low T_{avg} trip in any two-out-of-four RCS loops, or if there is a one-out-of-one low pressure trip in any two-out-of-four steam lines. Since the accidents that this event protects against cause both low steam line pressure and low T_{avg}, provision of one channel per loop or steam line ensures no single random failure can disable both of these Functions. The steam line pressure channels provide no control inputs. The T_{avg} channels provide control inputs, but the control function cannot initiate events that the Function acts to mitigate.

The Allowable Value for high steam flow is a linear function that varies with power level. The function is a turbine first stage pressure corresponding to approximately 54% of full steam flow between 0% and 20% load to approximately 110% of full steam flow at 100% load. The nominal trip setpoint is similarly calculated.

With the transmitters located inside the containment (RCS temperature and steam line flow) or inside the auxiliary feedwater building (steam pressure), it is possible for them to experience adverse steady state environmental conditions during an SLB event. Therefore, the Trip Setpoint reflects both steady state and adverse environmental instrument uncertainties.

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This Function must be OPERABLE in MODES 1, 2, and 3 when any MSIV is open because a secondary side break or stuck open valve could result in the rapid depressurization of the steam line(s). SLB may be addressed by Containment Pressure High (inside containment) or by High Steam Flow in Two Steam Lines coincident with Steam Line Pressure – Low, for Steam Line Isolation, followed by High Differential Pressure Between Two Steam Lines, for SI. This Function is not required to be OPERABLE in MODE 4, 5, or 6 because there is insufficient energy in the secondary side of the unit to cause an accident.

2. Containment Spray

Containment Spray provides three primary functions:

1. Lowers containment pressure and temperature after an HELB in containment;

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

3. Adjusts the pH of the water in the containment and recirculation sump after a large break LOCA.

These functions are necessary to:

- Ensure the pressure boundary integrity of the containment structure;

- Limit the release of radioactive iodine to the environment; and

- Minimize corrosion of the components and systems inside containment following a LOCA.

The containment spray actuation signal starts the containment spray pumps. Water is drawn from the RWST by the containment spray pumps and mixed with a sodium

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

hydroxide solution from the spray additive tank. When the RWST reaches a specified minimum level, the spray pumps are secured. RHR or recirculation pumps will be used if continued containment spray is required. Containment spray is actuated automatically by Containment Pressure-High High.

a. Containment Spray-Manual Initiation

Manual initiation of containment spray (CS) requires that two pushbuttons in the control room be depressed simultaneously which will actuate both trains of CS. Two pushbuttons must be depressed simultaneously to minimize the potential for an inadvertent actuation of CS which could have serious consequences. Each CS pushbutton closes one of the two contacts required to start CS train A and one of the two contacts required to start CS train B; depressing both pushbuttons closes both of the contacts required to start CS train A and both of the contacts required to start CS train B. Two channels (contacts) are required to be Operable for CS train A and two channels (contacts) are required to be Operable for CS train B. Failure of one manual pushbutton will result in one inoperable channel in both trains.

Note that Manual Initiation of containment spray also actuates Phase B containment isolation and containment ventilation isolation.

b. Containment Spray-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 containment spray must be OPERABLE in MODES 1, 2, and 3 when there is a potential for an accident to occur, and sufficient

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

energy in the primary or secondary systems to pose a threat to containment integrity due to overpressure conditions. 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. However, because of the number of components actuated on a containment spray, 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 and secondary systems to result in containment overpressure. In MODES 5 and 6, there is also adequate time for the operators to evaluate unit conditions and respond, to mitigate the consequences of abnormal conditions by manually starting individual components.

c. Containment Spray-Containment Pressure Hi-Hi

This signal provides protection against a LOCA or an SLB inside containment. The transmitters (d/p cells) are located outside of containment with the sensing line (high pressure side of the transmitter) located inside containment. The transmitters and electronics are located outside of containment. Thus, they will not experience any adverse environmental conditions and the Trip Setpoint reflects only steady state instrument uncertainties.

This Function requires the bistable output to energize to perform its required action. It is not desirable to have a loss of power actuate containment spray, because the consequences of an inadvertent actuation of containment spray could be serious. Therefore, the IP3 design consists of 2 sets of 3 channels (i.e., 6 pressure instruments) and 2 channels from each set of 3 are required to energize to actuate Containment Spray. This configuration provides sufficient redundancy to prevent a single failure from

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

causing or preventing Containment Spray initiation even when testing with one inoperable channel already in trip. The Required Actions for an inoperable channel associated with this Function decreases the probability of an inadvertent actuation by allowing no more than one channel per set to be placed in trip.

Containment pressure is not used for control; therefore, this arrangement exceeds the minimum redundancy requirements.

Containment Pressure- High High must be OPERABLE in MODES 1, 2, and 3 when there is sufficient energy in the primary and secondary sides to pressurize the containment following a pipe break. In MODES 4, 5, and 6, there is insufficient energy in the primary and secondary sides to pressurize the containment and reach the Containment Pressure High High setpoint.

3. Containment Isolation

Containment Isolation provides isolation of the containment atmosphere, and selected process systems that penetrate containment. This Function is necessary to prevent or limit the release of radioactivity to the environment in the event of a large break LOCA.

There are two separate Containment Isolation signals, Phase A and Phase B. Phase A isolation isolates all automatically isolable process lines exiting containment, except component cooling water (CCW) and RCP seal return, at a relatively low containment pressure indicative of primary or secondary system leaks. For these types of events, forced circulation cooling using the reactor coolant pumps (RCPs) and SGs is the preferred (but not required) method of decay heat removal. Since CCW or RCP seal injection and return are required to support RCP operation, not isolating CCW and RCP seal return on the low pressure Phase A signal enhances unit safety by allowing operators to use forced RCS circulation to cool the unit.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Isolating these functions on the low pressure signal may force the use of feed and bleed cooling, which could prove more difficult to control.

Phase A containment isolation is actuated automatically by SI, or manually via the actuation logic. All process lines exiting containment, with the exception of CCW and RCP seal return, are isolated. CCW and RCP seal return are not isolated at this time to permit continued operation of the RCPs with cooling water flow to the thermal barrier heat exchangers and oil coolers. All process lines not equipped with remote operated isolation valves are manually closed, or otherwise isolated, prior to MODE 4 except those manual isolation valves needed to support plant operations.

Manual Phase A Containment Isolation is accomplished by either of two pushbuttons in the control room. Either push button actuates both trains. Note that manual actuation of Phase A Containment Isolation also actuates Containment Ventilation Isolation.

The Phase B signal isolates CCW and RCP seal return. This occurs at a relatively high containment pressure that is indicative of a large break LOCA or an SLB. For these events, forced circulation using the RCPs is no longer desirable. Isolating the CCW at the higher pressure does not pose a challenge to the containment boundary because the CCW System is a closed loop inside containment. Although some CCW system components may not meet all of the ASME Code requirements applied to the containment itself, the system is continuously pressurized to a pressure greater than the Phase B setpoint. Thus, routine operation demonstrates the integrity of the system pressure boundary for pressures exceeding the Phase B setpoint. Furthermore, because system pressure exceeds the Phase B setpoint, any system leakage prior to initiation of Phase B isolation would be into containment. Therefore, the combination of CCW System design and Phase B isolation ensures the CCW System is not a potential path for radioactive release from containment.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Phase B containment isolation is actuated by Containment Pressure-High High, or manually, via the actuation logic, as previously discussed. For containment pressure to reach a value high enough to actuate Containment Pressure-High High, a large break LOCA or SLB must have occurred and containment spray must have been actuated. RCP operation will no longer be required and CCW and seal return to the RCPs are, therefore, no longer necessary. The RCPs can be operated with seal injection flow alone and without CCW flow to the thermal barrier heat exchanger.

Manual Phase B Containment Isolation is accomplished by either of two pushbuttons in the control room. Either pushbutton actuates both trains. Manual Phase B Containment Isolation is also initiated by Containment Spray manual pushbuttons. 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. Either pushbutton actuates both trains. Note that manual initiation of Phase A Containment Isolation also actuates Containment Ventilation Isolation.

(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

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

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 only if needed 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.

(3) Phase A Isolation-Safety Injection

Phase A Containment Isolation is also initiated by all Functions that initiate SI. The Phase A Containment Isolation requirements for these 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.

b. Containment Isolation-Phase B Isolation

Phase B Containment Isolation is accomplished by Manual Initiation, Automatic Actuation Logic and Actuation Relays, and by Containment Pressure channels (the same channels that actuate Containment Spray, Function 2). The Containment Pressure trip of Phase B Containment Isolation is energized to trip in order to

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

minimize the potential of spurious trips that may damage the RCPs.

(1) Phase B Isolation-Manual Initiation

Manual Phase B Containment Isolation is accomplished by either of two pushbuttons in the control room. Either pushbutton actuates both trains.

(2) Phase B Isolation-Automatic Actuation Logic and Actuation Relays

Manual and automatic initiation of Phase B 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. However, because of the number of components actuated on a Phase B 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 B 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.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

(3) Phase B Isolation-Containment Pressure Hi-Hi

The basis for containment pressure MODE applicability is as discussed for ESFAS Function 2.c above.

4. Steam Line Isolation

Isolation of the main steam lines provides protection in the event of an SLB inside or outside containment. Rapid isolation of the steam lines will limit the steam break accident to the blowdown from one SG, even if Main Steam Check Valve fails. For an SLB upstream of the main steam isolation valves (MSIVs), inside or outside of containment, closure of the MSIVs limits the accident to the blowdown from only the affected SG. For an SLB downstream of the MSIVs, closure of the MSIVs terminates the accident.

a. Steam Line Isolation-Manual Initiation

Manual initiation of Steam Line Isolation can be accomplished from the control room. Each main steam isolation valve (MSIV) will close if either of two solenoid valves in parallel (channel A and channel B) are opened. The pair of solenoid valves associated with each MSIV are operated by a single switch and there is a separate switch for each MSIV. Each of these switches actuates two channels. Except for the switch in the control room which is common to both channels, there are two separate and redundant circuits (channel A and channel B) capable of closing each MSIV. Therefore, the LCO requires 2 channels per MSIV and each MSIV is considered a separate Function.

b. Steam Line 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.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Manual and automatic initiation of steam line isolation must be OPERABLE in MODES 1, 2, and 3 when there is sufficient energy in the RCS and SGs to have an SLB or other accident. This could result in the release of significant quantities of energy and cause a cooldown of the primary system. The Steam Line Isolation Function is required in MODES 2 and 3 unless all MSIVs are closed. In MODES 4, 5, and 6, there is insufficient energy in the RCS and SGs to experience an SLB or other accident releasing significant quantities of energy.

c. Steam Line Isolation-Containment Pressure (Hi-Hi)

This Function actuates closure of the MSIVs in the event of a LOCA or an SLB inside containment to limit the mass and energy release to containment. The transmitters (d/p cells) are located outside containment. Containment Pressure-High-High provides no input to any control functions. The transmitters and electronics are located outside of containment. Thus, they will not experience any adverse environmental conditions, and the Trip Setpoint reflects only steady state instrument uncertainties.

The IP3 design consists of 2 sets of 3 channels and 2 channels from each set of 3 are required to energize to actuate steam line isolation on high pressure in the containment. This is the same logic that initiates Containment Spray. Therefore, this logic is designed to provide sufficient redundancy to prevent a single failure from causing or preventing Containment Spray initiation even when testing with one inoperable channel already in trip. The Required Action for an inoperable channel associated with this Function is modified by a Note that permits no more than one channel per set to be placed in trip to decrease the probability of an inadvertent actuation.

Containment Pressure-High-High must be OPERABLE in MODES 1, 2, and 3, when there is sufficient energy in

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

the primary and secondary side to pressurize the containment following a pipe break. This would cause a significant increase in the containment pressure, thus allowing detection and closure of the MSIVs. The Steam Line Isolation Function remains OPERABLE in MODES 2 and 3 unless all MSIVs are closed. In MODES 4, 5, and 6, there is not enough energy in the primary and secondary sides to pressurize the containment to the Containment Pressure – High-High setpoint.

d, e. Steam Line Isolation – High Steam Flow in Two Steam Lines Coincident with T_{avg}-Low or Coincident With Steam Line Pressure-Low

These Functions (4.d and 4.e) provide closure of the MSIVs during an SLB or inadvertent opening of a safety valve to limit RCS cooldown and the mass and energy release to containment.

These Functions were discussed previously as Functions 1.e. and 1.f.

These Functions must be OPERABLE in MODES 1 and 2, and in MODE 3, when a secondary side break or stuck open valve could result in the rapid depressurization of the steam lines unless all MSIVs are closed. These Functions are not required to be OPERABLE in MODES 4, 5, and 6 because there is insufficient energy in the secondary side of the unit to have an accident.

5. Feedwater Isolation

The function of the Feedwater Isolation signal is to stop the excessive flow of feedwater into the SGs. The Function is necessary to mitigate the effects of a high water level in the SGs, which could result in carryover of water into the steam lines and excessive cooldown of the primary

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

system. The SG high water level is due to excessive feedwater flows.

This Function is actuated by an SI signal. The RPS also initiates a turbine trip signal whenever a reactor trip is generated. In the event of SI, the unit is taken off line and the turbine generator must be tripped. The MFW System is also taken out of operation and the AFW System is automatically started. The SI signal was discussed previously.

Feedwater Isolation-Safety Injection

Feedwater Isolation is also initiated by all Functions that initiate SI. Therefore, there are two trains of this Function, one initiated by SI train A and one initiated by SI train B.

Feedwater Isolation Functions must be OPERABLE in MODES 1 and 2 and 3 except when all MBFPDVs or MBFRVs and associated low flow bypass valves are closed or isolated by a closed manual valve when the MFW System is 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, making it available during normal unit operation, during a loss of AC power and during a loss of MFW. The normal source of water for the AFW System is the condensate storage tank (CST). Additionally, City Water (CW) may be aligned to AFW to provide a backup water supply. The AFW System is aligned so that upon a motor driven pump start, flow is initiated to the respective SGs immediately.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

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 due to a loss of MFW and the resulting 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, the Trip Setpoint reflects the inclusion of both steady state and adverse environmental instrument uncertainties.

c. Auxiliary Feedwater-Safety Injection

An SI actuation 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-Loss of Offsite Power

A turbine trip in conjunction with a loss of offsite power to the safeguards buses will be accompanied by a loss of reactor coolant pumping power and the

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

subsequent need for some method of decay heat removal. The loss of offsite power (Non SI blackout signal) is detected by a voltage drop on 480 V bus 3A and/or 6A. Loss of power to either safeguards bus will start the turbine driven AFW pump 32 to ensure that at least one SG contains enough water to serve as the heat sink for reactor decay heat and sensible heat removal following the reactor trip following a loss of offsite power.

The LCO requires one Operable channel for bus 3A and one Operable channel for bus 6A. Either channel will start the turbine driven AFW pump. Therefore, a single failure of one channel of non-Safety Injection blackout sequence will not result in a loss of Function.

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 pump 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 pump 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 Feedwater Pumps

A Trip of either MBFW pump is an indication of a potential loss of MFW and the 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 MBFW pump is equipped

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

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 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 LCO requires one Operable channel for each operating MBFP. A trip of either MBFW pump starts both motor driven AFW pumps to ensure that at least one SG is available with water to act as the heat sink for the reactor.

Function 6.e must be OPERABLE in MODES 1 and 2. This ensures that at least one SG is provided with water to serve as the heat sink to remove reactor decay heat and sensible heat in the event of loss of normal feedwater. In MODES 3, 4, and 5, the MBFW pumps are shut down, and thus MBFW pump trip does not require automatic AFW initiation.

7. ESFAS Interlock-Pressurizer Pressure

The Pressurizer Pressure interlock permits a normal unit cooldown and depressurization without actuation of SI. With two-out-of-three pressurizer pressure channels (discussed previously) less than the setpoint, the operator can manually block the Pressurizer Pressure-Low SI signal. With two-out-of-three pressurizer pressure channels above the setpoint, the Pressurizer Pressure-Low is automatically enabled. The operator can also enable these trips by use of the respective manual blocking switches.

This Function must be OPERABLE in MODES 1, 2, and 3 to allow an orderly cooldown and depressurization of the

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

unit without the actuation of SI. The interlock Functions back up manual actions to ensure bypassable functions are in operation under the conditions assumed in the safety analyses. This Function does not have to be OPERABLE in MODE 4, 5, or 6 because system pressure must already be below the setpoint for the requirements of the heatup and cooldown curves to be met.

The ESFAS instrumentation satisfies Criterion 3 of 10 CFR 50.36.

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Note 1 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 3.3.2-1.

Note 2 specifies that when a channel or train is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 8 hours, provided the associated Function(s) maintains ESFAS trip capability. Upon completion of the Surveillance, or expiration of the 8 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is consistent with the assumptions of the instrumentation system reliability analysis (Ref. 7). That analysis demonstrated that the 8 hour testing allowance does not significantly reduce the probability that the ESFAS will trip when necessary.

In the event a channel's Trip Setpoint is found nonconservative with respect to the Allowable Value, or the transmitter, instrument Loop, signal processing electronics, or bistable is found inoperable, then all affected Functions provided by that channel must be declared inoperable and the LCO Condition(s) entered for the protection Function(s) affected. When the Required Channels in Table 3.3.2-1 are specified (e.g., on a per steam line, per loop, per SG, etc., basis), then the Condition may be entered separately for each steam line, loop, SG, etc., as appropriate.

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ACTIONS (continued)

When the number of inoperable channels in a trip function exceed those specified in one or other related Conditions associated with a trip function, then the unit is outside the safety analysis. Therefore, LCO 3.0.3 should be immediately entered if applicable in the current MODE of operation.

A.1

Condition A applies to all ESFAS protection functions.

Condition A addresses the situation where one or more channels or trains for one or more Functions are inoperable at the same time. The Required Action is to refer to Table 3.3.2-1 and to take the Required Actions for the protection functions affected. The Completion Times are those from the referenced Conditions and Required Actions.

B.1, B.2.1 and B.2.2

Condition B applies to manual initiation of:

- SI;
- Containment Spray;
- Phase A Isolation; and
- Phase B Isolation.

This action addresses the train orientation of the relay logic for the functions listed above. If a channel or train is inoperable, 48 hours is allowed to return it to an OPERABLE status. Note that for containment spray and Phase B isolation, failure of one or both channels in one train renders the train inoperable. Condition B, therefore, encompasses both situations.

The specified Completion Time is reasonable considering that there are two automatic actuation trains and another manual initiation train OPERABLE for each Function, and the low probability of an event occurring during this interval. If the

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ACTIONS

B.1, B.2.1 and B.2.2 (continued)

train cannot be restored to OPERABLE status, the unit must be placed in a MODE in which the LCO does not apply. This is done by placing the unit in at least MODE 3 within an additional 6 hours (54 hours total time) and in MODE 5 within an additional 30 hours (84 hours total time). The allowable 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, C.2.1 and C.2.2

Condition C applies to the automatic actuation logic and actuation relays for the following functions:

- SI;
- Containment Spray;
- Phase A Isolation; and
- Phase B Isolation.

This action addresses the train orientation of the relay logic and the master and slave relays. If one train is inoperable, 6 hours are allowed to restore the train to OPERABLE status. The specified Completion Time is reasonable considering that there is another train OPERABLE, and the low probability of an event occurring during this interval. If the train cannot be restored to OPERABLE status, the unit must be placed in a MODE in which the LCO does not apply. This is done by placing the unit in at least MODE 3 within an additional 6 hours (12 hours total time) and in MODE 5 within an additional 30 hours (42 hours total time). The 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.

BASES

ACTIONS

C.1, C.2.1 and C.2.2 (continued)

The Required Actions are modified by a Note that allows one train to be bypassed for up to 8 hours for surveillance testing, provided the other train is OPERABLE. This allowance is based on the reliability analysis assumption of WCAP-10271-P-A (Ref. 7) that 8 hours is required to perform channel surveillance.

D.1, D.2.1 and D.2.2

Condition D applies to:

- Containment Pressure-High;
- Pressurizer Pressure-Low;
- High Differential Pressure Between Steam Lines;
- High Steam Flow in Two Steam Lines Coincident With T_{avg}-Low or Coincident With Steam Line Pressure-Low; and
- SG Water level-Low Low.

If one channel is inoperable, 6 hours are allowed to restore the channel to OPERABLE status or to place it in the tripped condition. Generally this Condition applies to functions that operate on two-out-of-three logic. Therefore, failure of one channel places the Function in a two-out-of-two configuration. One channel must be tripped to place the Function in a one-out-of-two configuration that satisfies redundancy requirements.

Required Actions associated with High Steam Flow in Two Steam Lines Coincident With Tavg-Low or Coincident With Steam Line Pressure-Low are entered by treating Steam Flow, Tavg, and Steam Line Pressure as three separate Functions. The protective action is initiated on one-out-of-two high flow in any two-out-of-four steam lines if there is one-out-of-one low Tavg trip in any two-out-of-four RCS loops, or if there is a one-out-of-one low pressure trip in any two-out-of-four steam lines. This logic is

BASES

ACTIONS

D.1, D.2.1 and D.2.2 (continued)

acceptable because a single steam line fault will cause the remaining intact steam lines to pick up the full turbine load with the protective action initiated by the conditions in the non faulted steam lines. Therefore, a maximum of one channel of each of the three Functions may be placed in trip without creating a condition where a single failure will either cause or prevent the protective action.

Failure to restore the inoperable channel to OPERABLE status or place it in the tripped condition within 6 hours requires the unit be placed in MODE 3 within the following 6 hours and MODE 4 within the next 6 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. In MODE 4, these Functions are no longer required OPERABLE.

The Required Actions are modified by a Note that allows the inoperable channel to be bypassed for up to 8 hours for surveillance testing of other channels. The 6 hours allowed to restore the channel to OPERABLE status or to place the inoperable channel in the tripped condition, and the 8 hours allowed for testing, are justified in Reference 8.

E.1, E.2.1 and E.2.2

Condition E applies to:

- Steam Line Isolation Containment Pressure-(High High);
- Containment Spray Containment Pressure-(High, High); and
- Containment Phase B Isolation Containment Pressure-(High, High).

The IP3 design for the Containment Pressure (High High) ESFAS Function consists of 2 sets of 3 channels. This design requires

BASES

ACTIONS

E.1, E.2.1 and E.2.2 (continued)

that 2 channels from each set of 3 are energized to actuate the Containment Spray or Steam Line Isolation Functions. This configuration provides sufficient redundancy to prevent a single failure from causing or preventing containment spray initiation or steamline isolation even when testing with one inoperable channel per set already in trip.

Note that Condition E applies only when no more than one channel in one or both sets is inoperable. Otherwise, entry into LCO 3.0.3 is required. This is required because two inoperable channels from the same set that fail low could result in a loss of containment spray initiation or steamline isolation when a Containment Pressure (High High) ESFAS initiation is required. Additionally, this ensures that no more than one channel per set can be placed in trip which is required to decrease the probability of an inadvertent actuation of containment spray or steamline isolation if additional channels fail high.

An inoperable channel is placed in trip within 6 hours to limit the amount of time that a single failure of a different channel on the same set could result in the failure of containment spray or steamline isolation to actuate. With no more than one channel from each set in trip, a single failure will not cause or prevent containment spray initiation or steamline isolation. Failure to place an inoperable channel in trip within 6 hours, requires the unit be placed in MODE 3 within the following 6 hours and MODE 4 within the next 6 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. In MODE 4, these Functions are no longer required OPERABLE.

The Required Actions are modified by a Note that allows one additional channel to be bypassed for up to 8 hours for surveillance testing. Placing a second channel in the bypass condition for up to 8 hours for testing purposes is acceptable based on the results of Reference 7.

BASES

ACTIONS (continued)

F.1, F.2.1 and F.2.2

Condition F applies to:

- Manual Initiation of Steam Line Isolation; and
- Loss of Offsite Power (Non Safety Injection).

For the manual MSIV isolation Function, each MSIV will close if either of the two channels required per MSIV is tripped. If one channel is inoperable, the ability to tolerate a single failure is lost but manual isolation capability is maintained. Therefore, an inoperable channel cannot be placed in trip without causing an actuation and the inoperable channel must be restored to Operable to restore single failure protection. Additionally, since a single switch actuates both channels for each MSIV, the failure of a manual switch may result in the failure of both channels and a loss of Function. The specified Completion Time, 48 hours to restore an inoperable channel, is reasonable considering that there are two automatic actuation trains and another manual initiation train OPERABLE for each MSIV, and the low probability of an event occurring during this interval. Each MSIV is considered a separate Function.

For the Loss of Offsite Power (Non-Safety Injection) Function, either channel (bus 3A or bus 6A) will start the turbine driven AFW pump. If one channel is inoperable, the AFW starting Function for the turbine driven AFW pump on loss of offsite power is maintained by the channel associated with the other bus. Two inoperable channels result in a loss of this Function; therefore, entry into LCO 3.0.3 is requried.

For the Loss of Offsite Power (Non-Safety Injection) Function, an inoperable channel cannot be placed in trip without causing an actuation: therefore, an inoperable channel must be restored to Operable. The specified Completion Time, 48 hours to restore an inoperable channel, is reasonable considering that this is a Non-Safety Injection start of the AFW, the availability of manual starting capability, and the low probability of an event

BASES

ACTIONS

F.1, F.2.1 and F.2.2 (continued)

occurring during this interval. Additionally, other Functions, in particular SG Water Level-Low Low, provide the primary protection against a loss of heat sink.

If either of these Functions cannot be returned to OPERABLE status, 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 experience, to reach the required unit conditions from full power in an orderly manner and without challenging unit systems. In MODE 4, the unit does not have any analyzed transients or conditions that require the explicit use of the protection functions noted above.

G.1, G.2.1 and G.2.2

Condition G applies to the automatic actuation logic and actuation relays for the Steam Line Isolation and AFW actuation Functions.

The action addresses the train orientation of the relay logic and the actuation relays for these functions. If one train is inoperable, 6 hours are allowed to restore the train to OPERABLE status. The Completion Time for restoring a train to OPERABLE status is reasonable considering that there is another train OPERABLE, and the low probability of an event occurring during this interval. If the train cannot be returned to OPERABLE status, the unit must be brought to MODE 3 within the next 6 hours and MODE 4 within the following 6 hours unless the plant can be placed outside of the Applicable MODE or Conditions by other means (e.g., shutting all MSIVs). 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. Placing the unit in MODE 4 removes all requirements for OPERABILITY of the protection channels and actuation functions. In this MODE, the unit does not have analyzed transients or conditions that require the explicit use of the protection functions noted above.

BASES

ACTIONS

G.1, G.2.1 and G.2.2 (continued)

The Required Actions are modified by a Note that allows one train to be bypassed for up to 8 hours for surveillance testing provided the other train is OPERABLE. This allowance is based on the reliability analysis (Ref. 7) assumption that 8 hours is the average time required to perform channel surveillance.

H.1 and H.2

Condition H applies to the automatic actuation logic and actuation relays for the Feedwater Isolation Function.

This action addresses the train orientation of the relay logic and the actuation relays for this Function. If one train is inoperable, 6 hours are allowed to restore the train to OPERABLE status or the unit must be placed in MODE 3 within the following 6 hours unless the plant can be placed outside of the Applicable MODE or Conditions by other means (e.g., shutting all MBFPDVs or MBFRVs and associated bypass valves). The Completion Time for restoring a train to OPERABLE status is reasonable considering that there is another train OPERABLE, and the low probability of an event occurring during this interval. 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 unit systems. These Functions are no longer required in MODE 3. Placing the unit in MODE 3 removes all requirements for OPERABILITY of the protection channels and actuation functions. In this MODE, the unit does not have analyzed transients or conditions that require the explicit use of the protection functions noted above.

The Required Actions are modified by a Note that allows one train to be bypassed for up to 8 hours for surveillance testing provided the other train is OPERABLE. This allowance is based on the reliability analysis (Ref. 7) assumption that 8 hours is the average time required to perform channel surveillance.

BASES

ACTIONS (continued)

I.1, I.2 and J.1

Condition I applies to the AFW pump start on trip of either Main Boiler Feedwater pump.

The OPERABILITY of the AFW System must be assured by allowing automatic start of the AFW System pumps. 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. Therefore, when a channel is inoperable, Required Action I.1, verifies that one channel associated with an operating MBFP is OPERABLE to ensure that there is no loss of function. Otherwise, entry into LCO 3.0.3 is required. If both MBFPs are operating, Required Action I.2 allows 48 hours to restore redundancy by requiring one channel associated with each operating MBFP to be OPERABLE. Continued operating without redundant channels when only one 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.

If the function cannot be returned to an OPERABLE status, 6 hours are allowed by Required Action J.1 to place the unit in MODE 3. 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 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.

K.1, K.2.1 and K.2.2

Condition K 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

BASES

ACTIONS

K.1, K.2.1 and K.2.2 (continued)

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 experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. Placing the unit in MODE 4 removes all requirements for OPERABILITY of this interlock.

SURVEILLANCE REQUIREMENTS

The SRs for each ESFAS Function are identified by the SRs column of Table 3.3.2-1.

A Note has been added to the SR Table to clarify that Table 3.3.2-1 determines which SRs apply to which ESFAS Functions.

Note that each channel of process protection supplies both trains of the ESFAS. When testing an individual channel, the SR is not met until both train A and train B logic are tested. The CHANNEL CALIBRATION and COTs are performed in a manner that is consistent with the assumptions used in the setpoint methodology described in Reference 6.

SR 3.3.2.1

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

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.1 (continued)

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.

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including indication and reliability. 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 checks of channels during normal operational use of the displays associated with the LCO required channels.

SR 3.3.2.2

SR 3.3.2.2 is the performance of an ACTUATION LOGIC TEST. The relay logic is tested every 31 days on a STAGGERED TEST BASIS. The train being tested is placed in the bypass condition, thus preventing inadvertent actuation. All possible logic combinations are tested for each protection function required in Table 3.3.2-1. 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 31 days on a STAGGERED TEST BASIS is adequate. It is based on industry operating experience, considering instrument reliability and operating history data.

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

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.3 (continued)

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 (with the exception of the transmitter sensing device) will perform the intended Function. Setpoints must be found within the calibration acceptance criteriea.

The "as found" and "as left" values must also be recorded and reviewed. 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 (Ref. 6).

The Frequency of 92 days is justified in Reference 7.

SR 3.3.2.5

SR 3.3.2.5 is the performance of a SLAVE RELAY TEST. The SLAVE RELAY TEST is the energizing of the slave relays. Contact operation is verified in one of two ways. Actuation equipment that may be operated in the design mitigation MODE is either allowed to function, or is placed in a condition where the circuit operation can be verified without operation of the equipment. Actuation equipment that may not be operated in the design mitigation MODE is prevented from operation. Alternately, contact operation may be verified by a continuity check of the circuit containing the slave relay. This test is performed every

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.5 (continued)

24 months. The Frequency is adequate, based on industry operating experience, considering instrument reliability and operating history data.

SR 3.3.2.6

SR 3.3.2.6 is the performance of a TADOT. This test is a check of the Manual Actuation Functions and AFW pump start on trip of either MBFW pump or loss of offsite power (non SI). It is performed every 24 months. Each Manual Actuation Function is tested up to, and including, the master relay coils. In some instances, the test includes actuation of the end device (i.e., pump starts, valve cycles, etc.). The Frequency is adequate, based on industry operating experience and is consistent with the typical refueling cycle. The SR is modified by a Note that excludes verification of setpoints during the TADOT for manual initiation Functions. The manual initiation Functions have no associated setpoints.

SR 3.3.2.7

SR 3.3.2.7 is the performance of a CHANNEL CALIBRATION.

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 measured parameter within the necessary range and accuracy.

CHANNEL CALIBRATIONS must be performed consistent with the assumptions of the unit specific setpoint methodology (Ref. 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.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.7 (continued)

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

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

REFERENCES

1. FSAR, Chapter 6.

2. FSAR, Chapter 7.

3. FSAR, Chapter 14.

4. IEEE-279-1968.

5. 10 CFR 50.49.

6. Engineering Standards Manual IES-3 and IES-3B, Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3)

7. WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.

8. Consolidated Edison Company of New York, Inc. Indian Point Nuclear Generating Station Unit No. 3 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, March 1975.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.2:
"Engineered Safety Feature Actuation System (ESFAS) Instrumentation"

PART 2:

CURRENT TECHNICAL SPECIFICATION PAGES

Annotated to show differences between CTS and ITS

CTS pages and associated TSCRs annotated for this ITS Specification :

CTS Page No.	Effective Amendment	Annotated Amendment	TSCR No.	TSCR Description	ITS Status of TSCR
3.5-1	26	26	No TSCRs	No TSCRs for this Page	N/A
3.5-2	65	65	IPN 96-124	AOT for ESF Initiation Instrumentation (Needs Supplement)	Incorporated
3.5-3	26	26	No TSCRs	No TSCRs for this Page	N/A
3.5-4	106	106	No TSCRs	No TSCRs for this Page	N/A
3.5-5	5-17-90	5-17-90	No TSCRs	No TSCRs for this Page	N/A
3.5-6	154	154	No TSCRs	No TSCRs for this Page	N/A
3.5-7	154 (9/22/98)	154	No TSCRs	No TSCRs for this Page	N/A
3.5-7	154 (9/22/98)	154	181	Amednment 181	
3.5-8	154	154	No TSCRs	No TSCRs for this Page	N/A
3.5-9	154	154	No TSCRs	No TSCRs for this Page	N/A
T 3.5-1(1)	154	154	No TSCRs	No TSCRs for this Page	N/A

Technical Specification 3.3.2:

"Engineered Safety Feature Actuation System (ESFAS) Instrumentation"

T 3.5-3(1)	113	113	No TSCRs	No TSCRs for this Page	N/A
T 3.5-3(2)	151	151	No TSCRs	No TSCRs for this Page	N/A
T 3.5-3(3)	151	151	IPN 96-124	AOT for ESF Initiation Instrumentation (Needs Supplement)	Incorporated
T 3.5-4(1)	151	151	No TSCRs	No TSCRs for this Page	N/A
T 3.5-4(2)	151	151	No TSCRs	No TSCRs for this Page	N/A
4.1-1	97	97	No TSCRs	No TSCRs for this Page	N/A
4.1-3	148	148	No TSCRs	No TSCRs for this Page	N/A
4.1-4	107	107	No TSCRs	No TSCRs for this Page	N/A
4.1-5	107 TSCR 97-156	107 TSCR 97-156	IPN 97-156	SR Freq for Main Turbine Stop and Control Valves	Incorporated
T 4.1-1(1)	170 TSCR 98-043	170 TSCR 98-043	IPN 98-043	Instrument Channel Surveillance Intervals Extended to 24 Months	Incorporated
T 4.1-1(2)	169	169	No TSCRs	No TSCRs for this Page	N/A
T 4.1-1(3)	168 TSCR 98-043	168 TSCR 98-043	IPN 98-043	Instrument Channel Surveillance Intervals Extended to 24 Months	Incorporated
T 4.1-1(4)	169 TSCR 98-043	169 TSCR 98-043	IPN 98-043	Instrument Channel Surveillance Intervals Extended to 24 Months	Incorporated
T 4.1-1(5)	169 TSCR 98-043	169 TSCR 98-043	IPN 98-043	Instrument Channel Surveillance Intervals Extended to 24 Months	Incorporated
4.5-1	142	142	No TSCRs	No TSCRs for this Page	N/A
4.5-2	172 TSCR 98-043	172 TSCR 98-043	IPN 98-043	Instrument Channel Surveillance Intervals Extended to 24 Months	Incorporated
4.7-1	133	133	No TSCRs	No TSCRs for this Page	N/A

A.1

3.5 INSTRUMENTATION SYSTEMS

Operational Safety Instrumentation

~~**Applicability**~~

~~Applies to plant instrumentation systems.~~ A.2

~~**Objectives**~~

~~To provide for automatic initiation of the Engineered Safety Features in the event that principal process variable limits are exceeded, and to delineate the conditions of the plant instrumentation and safety circuits necessary to ensure reactor safety.~~

Specification

LCO 3.3.2 Applicability

~~3.5.1~~ When the plant is not in the cold shutdown condition, the Engineered Safety Features initiation instrumentation setting limits shall be as stated in Table ~~3.5-1~~ 3.3.2-1. A.3 to A.30

~~3.5.~~2 For instrumentation testing or instrumentation channel failure, plant operation shall be permitted to continue in accordance with Tables ~~3.5-2 through 3.5-4~~ 3.3.2-1. ~~No more than one channel of a particular protection channel set shall be tested at the same time. By definition, an instrumentation channel failure shall not be regarded as a channel being tested.~~ A.31 L.2

LCO 3.3.2

3.5.3 In the event the number of in-service channels of a particular function is less than the minimum number of Operable Channels (Col. 3), or the Minimum Degree of Redundancy (Col. 4) cannot be achieved, operation shall be limited according to the requirement shown in Column 5 of Tables 3.5-2 through 3.5-4. L.3

LCO 3.3.2 Req Act A.1

Add Actions Note: Separate Condition entry A.32

Paragraph b of DOCs A.3 to A.30

3.3.2, Req Actions	~~3.5.4~~	In the event of instrumentation channel failure permitted by specification 3.5.2, the Minimum Degree of Redundancy listed in Tables 3.5-2 through 3.5-4 may be reduced by one, but to not less than zero, and the Minimum Number of Operable Channels listed in these tables may be reduced by one, but not to less than one (except as noted in Table 3.5-3) for a period of 8 hours while instrument channels are tested. The failed channel may be blocked to prevent an unnecessary reactor trip during this time. ~~In the case of three loop operation, the out-of-service channel is permitted to be bypassed during the test period~~ (A.34) (A.36) (A.33)
Actions Note 2		
Note to Req Actions C.1, D.1, E.1, G.1, H.1		
T3.3.2-1, #8, T3.3.2-1, Note b, Action J.1,	~~3.5.5~~	The low pressurizer pressure safety injection trip shall be unblocked when the pressurizer pressure is ≥ 2000 psig. (1998.24) (L.1) (A.30)
SEE ITS 3.3.1	3.5.6	At least one source range and one intermediate range nuclear instrument channel shall be operable prior to reactor start-up.
SEE ITS 3.3.3	3.5.7	When the reactor is not in the cold shutdown condition, the instrumentation requirements as stated in Table 3.5-5 shall be met.
T3.3.2-1, #1.c	3.5.8	A minimum of two channels of containment pressure must be operable when T_{avg} is greater than 350°F. (A.5)

TSCR 96-124 not shown

Basis

Instrumentation has been provided to sense accident conditions and to initiate operation of the Engineered Safety Features (1).

Safety Injection System Actuation

Protection against a Loss of Coolant or Steam Break accident is brought about by automatic actuation of the Safety Injection System which provides emergency cooling and reduction of reactivity. A.1

The Loss of Coolant Accident is characterized by depressurization of the Reactor Coolant System and rapid loss of reactor coolant to the containment. The Engineered Safety Features have been designed to sense the effects of the Loss of Coolant accident by detecting low pressurizer pressure and generate signals actuating the SIS active phase based upon these signals. The SIS active phase is also actuated by a high containment pressure signal (Hi-Level) brought about by loss of high enthalpy coolant to the containment. This actuation signal acts as a backup to the low pressurizer pressure signal actuation of the SIS and also adds diversity to protection against loss of coolant.

Signals are also provided to actuate the SIS upon sensing the effects of a steam line break accident. Therefore, SIS actuation following a steam line break is designed to occur upon sensing high differential steam pressure between any two steam generators or upon sensing high steam line flow in coincidence with low reactor coolant average temperature or low steam line pressure. A time delay of no greater than six (6) seconds for high steam flow SIS actuation is included to compensate for instrument lag, thus avoiding spurious high steam flow SIS actuations.

The increase in the extraction of RCS heat following a steam line break results in reactor coolant temperature and pressure reduction. For this reason protection against a steam line break accident is also provided by low pressurizer pressure signals actuating safety injection.

Protection is also provided for a steam line break in the containment by actuation of SIS upon sensing high containment pressure.

SIS actuation injects highly borated fluid into the Reactor Coolant System in order to counter the reactivity insertion brought about by cooldown of the reactor coolant which occurs during a steam line break accident.

A.1

Containment Spray

The Engineered Safety Features actuation system also initiates containment spray upon sensing a high containment pressure signal (Hi-Hi Level). The containment spray acts to reduce containment pressure in the event of a loss of coolant or steam line break accident inside the containment. The spray cools the containment directly and limits the release of fission products by absorbing iodine should it be released to the containment.

Containment spray is designed to be actuated at a higher containment pressure (~ 50% of containment design pressure) than the SIS (~ 10% of containment design pressure). Since spurious actuation of containment spray is to be avoided, it is automatically initiated only on coincidence of Hi-Hi Level containment pressure sensed by both sets of two-out-of-three containment pressure signals.

Steam Line Isolation

Steam line isolation signals are initiated by the Engineered Safety Features closing all steam line stop valves. In the event of a steam line break, this action prevents continuous, uncontrolled steam release from more than one steam generator by isolating the steam lines on high containment pressure (Hi-Hi Level) or high steam line flow. Protection is afforded for breaks inside or outside the containment even when it is assumed that there is a single failure in the steam line isolation system.

A.1

Amendment No. 28, Letter From NRC, dated May 17, 1990

Feedwater Line Isolation

The feedwater lines are isolated upon actuation of the Safety Injection System in order to prevent excessive cooldown of the reactor coolant system. This mitigates the effect of an accident such as steam break which in itself causes excessive coolant temperature cooldown. Feedwater line isolation also reduces the consequences of a steam line break inside the containment, by stopping the entry of feedwater.

Containment Vent and Purge

The containment vent and purge valves are isolated upon actuation of the Safety Injection System, Containment Spray System, or upon receipt of a high containment radiation signal. In the event of an accident, this action prevents a continuous radioactive release via the Containment Vent and Purge System.

Allowable Values

Table 3.5-1 provides the "allowable values" for Engineered Safety Features instrumentation. The "allowable values" represent the limit placed on the "as-found" condition for an instrument loop. If the "as-found" condition measured during calibration is within the "allowable value," the instrument loop will satisfy the system and safety requirements. [6]

1. The Hi-Level containment pressure value is about 10% of containment design pressure. Initiation of Safety Injection protects against loss of coolant[2] or steam line break[3] accidents as discussed in the safety analysis.

2. The Hi-Hi Level containment pressure value is about 50% of containment design pressure. Initiation of Containment Spray and Steam Line Isolation protects against large loss of coolant[2] or steam line break accidents[3] as discussed in the safety analysis.

3. The pressurizer low pressure value is substantially below system operating pressure limits. However, it is sufficiently high to protect against a loss of coolant accident as shown in the safety analysis[2]. The trip is bypassed below 2000 psig to prevent inadvertent actuation of the Engineered Safeguards when the reactor is shutdown.

A.1

4. The steam line high differential pressure value is well below those differential pressures expected in the event of a large steam line break accident as shown in the safety analysis[3].

5. The high steam line flow measurement ΔP value is approximately 49% of the full steam flow from no load to 20% load. Between 20% and 100% (full) load, the value for the flow measurement ΔP is ramped linearly with respect to first stage turbine pressure from 49% of the full steam flow to 110% of the full steam flow. High steam flow, coincident with low T_{avg} or low steam line pressure, will initiate safety injection in the case of a large steam line break accident. The coincident low T_{avg} value for SIS and steam line isolation initiation is below the hot shutdown value. The coincident steam line pressure value is below the full load operating pressure. The safety analysis shows that these values provide protection in the event of a large steam line break.[3]

Instrument Operating Conditions

During plant operations, the complete instrumentation systems will normally be in service. Reactor safety is provided by the Reactor Protection System, which automatically initiates appropriate action to prevent exceeding established limits. Safety is not compromised, however, by continuing operation with certain instrumentation channels out of service since provisions were made for this in the Plant design. This specification outlines limiting conditions for operation necessary to preserve the effectiveness of the Reactor Control and Protection System when any one or more of the channels are out of service.

A.1

Almost all reactor protection channels are supplied with sufficient redundancy to provide the capability for channel calibration and test at power. Exceptions are backup channels such as reactor coolant pump breakers. The removal of one trip channel on process control equipment is accomplished by placing that channel bistable in a tripped mode; e.g., a two-out-of-three circuit becomes a one-out-of-two circuit. A channel bistable may also be placed in a bypassed mode; e.g., a two-out-of-three circuit becomes a two-out-of-two circuit. The nuclear instrumentation system channels are not intentionally placed in a tripped mode since the test signal is superimposed on the normal detector signal to test at power. Testing of the NIS power range channel requires: (a) bypassing the Dropped Rod protection from NIS, for the channel being tested; and (b) defeating the ΔT protection CHANNEL SET that is being fed from the NIS channel and (c) defeating the power mismatch section of T_{avg} control channels when the appropriate NIS channel is being tested. However, the Rod Position System and remaining NIS channels still provide the dropped-rod protection. Testing does not trip the system unless a trip condition exists in a concurrent channel.

In the event that either the specified Minimum Number of Operable Channels or the Minimum Degree of Redundancy cannot be met, the reactor and the remainder of the plant is placed, utilizing normal operating procedures, in that condition consistent with the loss of protection.

The source range and the intermediate range nuclear instrumentation and the turbine and steam-feedwater flow mismatch trip functions are not required to be operable since they were not used in the transient and safety analysis (FSAR Section 14).

The shunt trip features of the reactor trip and bypass breakers were modified as a result of the Salem ATWS events[4]. Operability requirements for the reactor trip breakers and the reactor protection logic relays were added to the reactor protection instrument operating conditions as a result of NRC review of shunt trip modifications at Westinghouse plants[5]. Operability is demonstrated when the logic coincidence relays are tested to show they are capable of initiating a reactor trip. Reactor trip breakers are considered operable when tested to show they are capable of being opened: (a) by the undervoltage device and the shunt trip device independent of each other from an automatic trip signal and (b) from the Control Room Flight Panel manual trip during refueling outages. An exception of 72 hours is allowed before a reactor trip breaker is declared inoperable if only one of the diverse trip features (undervoltage or shunt trip) fails to open the breaker when tested.

A.1

Allowable values contained in these Technical Specifications are determined for the calibration of the complete instrument loop during required calibrations in a refueling cycle. The procedural allowable values for each specific component of the loop have been developed and are included in the applicable calibration or functional test(s). These procedural allowable values have taken into consideration the periodicity of the test and the specific components tested. The allowable value listed in the Technical Specifications can not normally be compared to the results of a specific test due to different calculation methods, but will require an engineering evaluation to determine if the Technical Specification allowable value was exceeded. The number assigned as the Technical Specification allowable value is the worst deviation from the nominal trip setpoint that can occur and still be bounded by setpoint calculations. In all cases the procedural allowable values will be equal to or more restrictive than the allowable values listed in the Technical Specifications.

References:

1) FSAR - Section 7.5
2) FSAR - Section 14.3
3) FSAR - Section 14.2.5
4) GL 83-28 - Item 4.3
5) GL 85-09
6) NYPA Report IP3-RPT-MULT-00763, Revision 1, "24 Month Operating Cycle Technical Specification Operability and Acceptance Criteria."

A.1

TABLE 3.5-1 (Sheet 1 of 2)

ENGINEERED SAFETY FEATURES INITIATION INSTRUMENT ALLOWABLE VALUES

	No. FUNCTIONAL UNIT	CHANNEL	ALLOWABLE VALUE	
T3.3.2-1, #1.c	1. High Containment Pressure (Hi Level)	Safety Injection	≤ 4.5 psig 4.80 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	≤ 24 psig 24.3 L.1	A.12 A.21 A.18
T3.3.2-1, #1.d	3. Pressurizer Low Pressure	Safety Injection	≥ 1700 psig 1684.64 L.1	A.6
T3.3.2-1, #1.e	4. High Differential Pressure Between Steam Lines	Safety Injection	≤ 150 psi 208 L.1	A.7
T3.3.2-1, #1.f 1.g	5. High Steam Flow in 2/4 Steam Lines Coincident with Low T_{avg} or Low Steam Line Pressure	a. Safety Injection	≤ 6 sec. time delay for SI actuation ≤ 49% of full steam flow at zero load 54.4 L.1	A.8 A.9
T3.3.2-1, 4.d 4.e		b. Steam Line Isolation T3.3.2-1, Note (C)	≤ 49% of full steam flow at 20% load ≤ 110% of full steam flow at full load ≥ 540°F T_{avg} 535.6 L.1 ≥ 600 psig steam line pressure 476.0 L.1	A.22 A.23
T3.3.2-1, 6.b	6. Steam Generator Water Level (low-low)	Auxiliary Feedwater	≥ 5% of narrow range instrument span each steam generator 3.54 L.1	A.26
T3.3.2-1 #6d	7.*a. 480v Bus Undervoltage Relay		≥ 200v**	
SEE ITS 3.3.5	b. 480v Bus Degraded Voltage Relay (Non-SI)		≥ 414v with a ≤45 sec time delay	SEE 3.3.5
SEE 3.3.5	c. 480v Bus Degraded Voltage Relay (Coincident SI)		≥ 414v with a ≤10 sec time delay	SEE 3.3.5

Amendment No. ~~28~~, ~~38~~, ~~34~~, ~~108~~, 154

Add Function 3.a.2 and Cond. C — A.14

Add Function 3.b.2 and Cond C — A.17

Add Function 1.a and Condition C — A4

Add Function 2.b and Condition C — A.11

Add Function 4.b and Cond G — A.20

Add Function 6.a and Cond. G — A.25

LA.1

A.34

TABLE 3.5 3 (Sheet 1 of 3)

INSTRUMENTATION OPERATING CONDITION FOR ENGINEERED SAFETY FEATURES

	NO.	FUNCTIONAL UNIT	1 NO. OF CHANNELS	2 NO. OF CHANNELS TO TRIP	3 MIN. NUMBER OF OPERABLE CHANNELS	4 MIN. DEGREE OF REDUNDANCY	5 OPERATOR ACTION IF CONDITIONS OF COL. 3 OR 4 CANNOT BE MET (Note 6)	
T3.3.2-1, #1.a	1.	SAFETY INJECTION						
		a. Manual	2	1	1	0 (2) M.1	Cold Shutdown (Req. Act B.2)	A.3
T3.3.2-1, #1.c		b. High Containment Pressure (Hi Level)	3	2	2	1 (3)	Cold Shutdown (Req. Act D.2) L.4	A.5
T3.3.2-1, #1.e		c. High Differential Pressure Between Steam Lines	3/steam line	2/steam line	2/steam line	1/steam line (3 per steam line)	Cold Shutdown (Req. Act D.2) L.4	A.7
T3.3.2-1, #1.d		d. Pressurizer Low Pressure (Note 3) (T.3.3.2-1, Note 3)	3	2	2	1 (3)	Cold Shutdown (Req. Act D.2) L.4	A.6
T3.3.2-1, #1.f #1.g		e. High Steam Flow in 2/4 Steam Lines Coincident with Low T_{avg} or Low Steam Line Pressure	2/steam line	1/2 in any 2 steam lines	1/steam line in each of 3 steam lines (2 per steam line)	1/steam line in each of 3 steam lines M.2	Cold Shutdown or main steam isolation valves closed (Table 3.3.2-1 Note (d))	A.8 A.9
			4 T_{avg} Signals	2	3	2 (4)		A.8
			4 Pressure Signals	2	3	2 (4)		A.9
T3.3.2-1, #8		f. Pressurizer Low Pressure (Automatic Unblock)	3	2	2 (Note 5)	1 (Note 5) (3)	Cold Shutdown (Req. Act K.1) L.4	A.30

Req. Act K.1

ITS 3.3.2

TABLE 3.5-3 (Sheet 2 of 3)

INSTRUMENTATION OPERATING CONDITION FOR ENGINEERED SAFETY FEATURES

	No. FUNCTIONAL UNIT	1 NO. OF CHANNELS	2 NO. OF CHANNELS TO TRIP	3 MIN. NUMBER OF OPERABLE CHANNELS	4 MIN. DEGREE OF REDUNDANCY	5 OPERATOR ACTION IF CONDITIONS OF COL. 3 OR 4 CANNOT BE MET (Note 6)	
	2. CONTAINMENT SPRAY						
T3.3.2-1, #2.a	a. Manual	2	2	2 per train / 2 trains 2	0 (Note 4) LA.1	Cold Shutdown Reg Act B.2	A.10
T3.3.2-1, #2.c	b. High Containment Pressure (Hi Hi Level)	2 sets of 3	2 of 3 in each set	2 per set 2 sets of 3	1/set	Cold Shutdown (Note 8) A.12.c Reg. Act E.2 L.4	A.12
T3.3.2-1, #6.b	3. AUXILIARY FEEDWATER						A.26
	a. Stm. Gen. Water Level-Low-Low				3 per steam generator	Reg. Act D.2	
	i. Start Motor Driven Pumps	3/stm. gen.	2 in any stm. gen.	2 chan. in each stm. gen.	1	Reduce system temperature such that T ≤ 350°F	
	ii. Start Turbine-Driven Pump	3/stm. gen.	2/3 in each of 2 stm. gen.	2 chan. in each stm. gen.	1	T ≤ 350°F	
T3.3.2-1, #6.c	b. S.I. Start Motor-Driven Pumps	(All	safety	injection	initiating	functions and requirements)	A.27
T3.3.2-1, #6.d	c. Station Blackout Start Turbine-Driven Pump (A.29.d) (M.3)	2	1	1	0 1 per bus / 2 buses	T ≤ 350°F Reg Act F.2 M.3	A.28
T3.3.2-1, #6.e	d. Trip of Main Feedwater Pumps Start Motor-Driven Pumps	2	1	1	0 1 per pump	Hot Shutdown Reg Act J.1 M.4	A.29

LA.1 A.34

ITS 3.3.2

TABLE 3.5-3 (Sheet 3 of 3)

INSTRUMENTATION OPERATING CONDITION FOR ENGINEERED SAFETY FEATURES

No. FUNCTIONAL UNIT	1 NO. OF CHANNELS	2 NO. OF CHANNELS TO TRIP	3 MIN. NUMBER OF OPERABLE CHANNELS	4 MIN. DEGREE OF REDUNDANCY	5 OPERATOR ACTION IF CONDITIONS OF COL. 3 OR 4 CANNOT BE MET (Note 6)
SEE ITS 3.3.5					
4. LOSS OF POWER					
a. 480v Bus Undervoltage Relay	2/bus	1/bus	1/bus	0	See Note 1
b. 480v Bus Degraded Voltage Relay	2/bus	2/bus	2/bus (See Note 2)	0	See Note 1
SEE ITS 3.4.12					
5. OVERPRESSURE PROTECTION SYSTEM (OPS)	3	2	2	1	See Note 7

SEE ITS 3.3.5

Note 1. If the 138KV and 13.8KV sources of offsite power are available and the conditions of column 3 or 4 cannot be met within 72 hours, then the requirements of 3.7.C.1 or 2 shall be met.

Note 2. If one channel becomes inoperable, it is placed in the trip position and the minimum number of operable channels is reduced by one.

T3.3.2-1, Note b — Note 3. Permissible to bypass if reactor coolant pressure is less than 2000 psig. 1998.24 — L.1 (A.6) (A.30)

~~Note 4. Must actuate 2 switches simultaneously~~ — LA.1

Reg Act K.1 — Note 5. The Minimum Number of Operable Channels and the Minimum Degree of Redundancy may be reduced to zero if the SI bypass is in the unblocked position. (A.30)

Reg Actions B.1 through J.1 — Note 6. If the condition of Column 3 or 4 cannot be met, (within 6 hours if no loss of function, immediately if loss of function) — L.3 the reactor shall be placed in the hot shutdown condition, utilizing normal operating procedures, within 4 hours of the occurrence. ~~If the conditions are not met within 24 hours of the occurrence, the reactor shall be placed in the cold shutdown condition, or the alternate condition, if applicable, within an additional 24 hours.~~ — M.5

(A.3 to A.30)

SEE ITS 3.4.12 — Note 7. Refer to Specification 3.1.A.8.

SEE ITS 3.4.12

~~Note 8. Main steam isolation valves may be closed in lieu of going to cold shutdown if the circuitry associated with closing the valves is the only portion inoperable.~~ (A.12.C) (A.35)

ITS 3.3.2

Amendment No. ~~38~~, ~~44~~, ~~54~~, ~~67~~, ~~113~~, 151

Add Automatic Actuation Logic and Actuation Relays

- Safety Injection — A.4
- Containment Spray — A.11
- Phase A Isol — A.14
- Phase B Isol — A.17
- Steam Line Isol — A.20
- AFW — A.25

TABLE 3.5-4 (Sheet 1 of 2)

INSTRUMENT OPERATING CONDITIONS FOR ISOLATION FUNCTIONS

	No. FUNCTIONAL UNIT	1 NO. OF CHANNELS	2 NO. OF CHANNELS TO TRIP	3 MIN. OPERABLE CHANNELS	4 MIN. DEGREE OF REDUNDANCY	5 OPERATOR ACTION IF CONDITIONS IN COLUMN 3 OR 4 CANNOT BE MET	
T3.3.2-1, #3a.3	1. CONTAINMENT ISOLATION a. Automatic Safety Injection (Phase A)	See Item	No. 1(b)	Refer to Function 1 of Table	3.5-3	Cold Shutdown (see note 1)	A.15
T3.3.2-1, #3.b.3	b. Containment Pressure (Phase B)	See Item	No. 2(b)	of Table	2 sets of 3 3.5-3	Reg. Act E.2 L.4 Cold Shutdown (see note 1)	A.18
T3.3.2-1, #3.a.1	c. Manual Phase A	2	1	1	2 M.1 0	Reg. Act B.2 Cold Shutdown (see note 1)	A.13
T3.3.2-1, #3.b.1	Phase B	See Item	No. 2(a)	of Table	2 M.1 3.5-3	Cold Shutdown (see note 1)	A.16
T3.3.2-1, #4.d #4.e	2. STEAM LINE ISOLATION a. High Steam Flow in 2/4 Steam Lines Coincident with Low T_{avg} or Low Steam Line Pressure	See Item	No. 1(e)	of Table Flow: 2 per steam line Tave: 1 per loop Press: 1 per steam line	3.5-3	Reg. Act D.2 L.4 Cold Shutdown or Main Steam Isolation Valves Closed (see note 1) Table 3.3.2-1, Note d	A.22 A.23
T3.3.2-1, #4.c	b. High Containment Pressure (Hi Hi Level)	See item	No. 2(b)	of Table 2 sets of 3	3.5-3	Reg. Act E.2 L.4 Cold Shutdown (see notes 1 and 2)	A.21
T3.3.2-1, #4.a	c. Manual	1/loop	1/loop	1/loop 2 per steam line M.1	0	Cold Shutdown or Main Steam Isolation Valves Closed (see note 1) Reg. Act F.2 L.4 Table 3.3.2-1, Note d	A.19

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ITS 3.3.2

TABLE 3.5-4 (Sheet 2 of 2)

LA.1

A.34

No.	FUNCTIONAL UNIT	1 NO. OF CHANNELS	2 NO. OF CHANNELS TO TRIP	3 MIN. OPERABLE CHANNELS	4 MIN. DEGREE OF REDUNDANCY	5 OPERATOR ACTION IF CONDITIONS IN COLUMN 3 OR 4 CANNOT BE MET
3.	FEEDWATER LINE ISOLATION					
a.	Safety Injection	See	Item	No. 1	of	Reg. Act H.2 Table 3.5-3
4.	CONTAINMENT VENT AND PURGE					
a.	Containment Radioactivity High (R11 and R12 monitor)	2	1	1	0	close all containment vent and purge valves when above cold shutdown
5.	PLANT EFFLUENT RADIOIODINE/PARTICULATE SAMPLING (sample line common with monitor R13)	1	NA	1	0	(see note 3)
6.	Main Steam Line Radiation Monitors	1/line	NA	1/line	0	(see note 3)
7.	Wide Range Plant Vent Monitor (R27)	1	NA	1	0	(see note 3)

T3.3.2-1, #5

A.24

SEE CTS MASTER MARKUP

NOTES

1. If the conditions of Columns 3 or 4 cannot be met, the reactor shall be placed in the hot shutdown condition, utilizing normal operating procedures, within 4 hours of the occurrence. ~~If the conditions are not met within 24 hours of the occurrence, the reactor shall be placed in the cold shutdown condition, or the alternate condition if applicable, within an additional 24 hours.~~ within 6 hours of no loss of function, immediately if loss of function

L.3

M.5

Table 3.3.2-1 Note (d)

~~2. Main steam isolation valves may be closed in lieu of going to cold shutdown if the circuitry associated with closing the valves is the only portion inoperable.~~

A.35

A.21.C

SEE CTS MASTER MARKUP

3. If the plant vent sampling capability, the wide-range vent monitor or the main steam line radiation monitors is/are: determined to be inoperable when the reactor is above the cold shutdown condition, then restore the sampling/monitoring capability within 72 hours or:
   a) Initiate a pre-planned alternate sampling/monitoring capability as soon as practical, but no later than 72 hours after identification of the failures. If the capability is not restored to operable status within 7 days, then,
   b) Submit a Special Report to the NRC pursuant to Technical Specification 6.9.2 within 14 days following the event outlining the action taken, the cause of the inoperability and the plans and schedule for restoring the system.

4 SURVEILLANCE REQUIREMENTS

4.1 OPERATIONAL SAFETY REVIEW

Applicability

Applies to items directly related to safety limits and limiting conditions for operation. Performance of any surveillance test outlined in these specifications is not required if the plant condition is the same as the condition into which the plant would be placed by an unsatisfactory result of that test. Failure to perform a surveillance requirement within the allowed surveillance interval (including extensions specified in definition 1.12), shall constitute noncompliance with the operability requirements of the limiting conditions for operation (LCOs). The time limits for associated action requirements are applicable at the time it is identified that a surveillance requirement has not been performed. Action requirements may be delayed for up to 24 hours to permit completion of the missed surveillance when the allowable outage time limits of the action requirements are less than 24 hours (i.e. for LCOs of less than 24 hours, a 24 hour delay period is permitted before entering the LCO; for LCOs greater than 24 hours, no delay period is permitted).

Objective

To specify the minimum frequency and type of surveillance to be applied to plant equipment and conditions.

Specification

LCO 3.3.2 SR TABLE Note

A. Calibration, testing, and checking of analog channel and testing of logic channel shall be performed as specified in Table ~~4.1-1~~ 3.3.2-1

B. Sampling and equipment tests shall be conducted as specified in Table ~~4.1-2 and 4.1-3~~, respectively.

A.1

Basis

A surveillance test is intended to identify conditions in a plant that would lead to a degradation of reactor safety. Should a test reveal such a condition, then the Technical Specifications require that, either immediately or after a specified period of time, the plant be placed in a condition which mitigates or eliminates the consequences of additional related casualties or accidents. If the plant is already in a

A.1

It permits an allowable extension of the normal surveillance interval to facilitate surveillance scheduling and consideration of plant operating conditions that may not be suitable for conducting the surveillance; e.g. transient conditions or other ongoing surveillance or maintenance activities. It also provides flexibility to accommodate the length of a fuel cycle for surveillances that are performed at each refueling outage and are specified with an 18-month or 24-month surveillance interval. It is not intended that this provision be used repeatedly as a convenience to extend surveillance intervals beyond that specified for surveillances that are not performed on an 18-month or 24-month basis. Likewise, it is not the intent that 24 month surveillances be performed during power operation unless it is consistent with safe plant operation. The limitation of Definition 1.12 is based on engineering judgement and the recognition that the most probable result of any particular surveillance being performed is the verification of conformance with the Surveillance Requirements. This provision is sufficient to ensure that the reliability ensured through surveillance activities is not significantly degraded beyond that obtained from the specified surveillance interval. The phrase "at least" associated with a surveillance frequency does not negate the 25% extension allowance of Definition 1.12; instead, it permits the performance of more frequent surveillance activities.

Based on experience in operation of both conventional and nuclear plant systems, when the plant is in operation, the minimum checking frequency of once per shift is deemed adequate for reactor and steam system instrumentation.

Calibration

Calibrations are performed to ensure the presentation and acquisition of accurate information.

The nuclear flux (linear level) channels are calibrated daily against a heat balance standard to account for errors induced by changing rod patterns and core physics parameters.

Other channels are subject only to the "drift" errors induced within the instrumentation itself and, consequently, can tolerate longer intervals between calibration. Process system instrumentation errors induced by drift can be expected to remain within acceptable tolerances if recalibration is performed at intervals of 18 or 24 months.

Substantial calibration shifts within a channel (essentially a channel failure) will be revealed during routine checking and testing procedures.

Thus, minimum calibration frequencies of once-per-day for the nuclear flux (linear level) channels, and 18 or 24 months for the process system channels is considered acceptable.

A.1

Testing

The minimum testing frequency for those instrument channels connected to the safety system is based on an average unsafe failure rate of 2.5×10^{-6} failure hrs. per channel. This is based on operating experience at conventional and nuclear plants. An unsafe failure is defined as one which negates channel operability and which, due to its nature, is revealed only when the channel is tested or attempts to respond to a bona fide signal.

For a specified test interval W and an M out of N redundant system with identical and independent channels having a constant failure rate λ, the average availability A is given by:

$$A = \frac{W - Q\,(W)^{N-M+2}}{W} = 1 - \frac{N!}{(N-M+2)!\,(M-1)!}(\lambda W)^{N-M+1}$$

where A is defined as the fraction of time during which the system is functional, and Q is the probability of failure of such a system during a time interval W.

For a 2-out-of-3 system A = 0.9999708, assuming a channel failure rate, λ, equal to 2.5×10^{-6} hr $^{-1}$ and a test interval, W, equal to 2160 hrs.

This average availability of the 2-out-of-3 system is high, hence the test interval of one quarter is acceptable.

Because of their greater degree of redundancy, the 1/3 and 2/4 logic arrays provide an even greater measure of protection and are thereby acceptable for the same testing interval. Those items specified for quarterly testing are associated with process components where other means of verification provide additional assurance that the channel is operable, thereby requiring less frequent testing.

~~Specified surveillance intervals for the Reactor Protection System and Engineered Safety Features have been determined in accordance with WCAP - 10271, Supplement 1, "Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System," and WCAP - 10271, Supplement 2, Revision 1, "Evaluation of Surveillance Frequencies and Out of Service Times for the Engineered Safety Features Actuation System," as approved by the NRC and documented in the SERs (letters to J. J. Sheppard from C. O. Thomas, dated February 21, 1985, and to R. A. Newton from C. E. Rossi, dated February 22, 1989). Surveillance intervals were determined based on maintaining an appropriate level of reliability of the Reactor Protection System and Engineered Safety Features instrumentation.~~

DELETED

A.1

Add SR 3.3.2.6 - Test Manual Initiation Capability (A.3) (A.16) (A.10) (A.19) (A.13)

TABLE 4.1-1 (Sheet 1 of 6)

MINIMUM FREQUENCIES FOR CHECKS, CALIBRATIONS AND TESTS OF INSTRUMENT CHANNELS

	Channel Description	Check	Calibrate	Test	Remarks
SEE ITS 3.3.1	1. Nuclear Power Range	S	D (1) M (3)*	Q (2)** Q (4)	1) Heat balance calibration 2) Bistable action (permissive, rod stop, trips) 3) Upper and lower chambers for axial offset 4) Signal to Δ T
	2. Nuclear Intermediate Range	S (1)	N.A.	P (2)	1) Once/shift when in service 2) Verification of channel response to simulated inputs
	3. Nuclear Source Range	S (1)	N.A.	P (2)	1) Once/shift when in service 2) Verification of channel response to simulated inputs
T3.3.2-1, #1.e #4.d	4. Reactor Coolant Temperature	S (##) (2) SR 3.3.2.1	24M SR 3.3.2.7	Q (1) SR 3.3.2.4	1) Overtemperature ΔT, overpower ΔT, and low T_{avg} (A.8) 2) Normal Instrument check interval is once/shift (A.22) T_{avg} instrument check interval reduced to every 30 minutes when: - T_{avg}-T_{ref} deviation and low T_{avg} alarms are not reset and, - Control banks are above 0 steps SEE ITS 3.4.2
	SEE ITS 3.4.1				
	5. Reactor Coolant Flow	S (##)	24M	Q	
	6. Pressurizer Water Level	S	24M	Q	
T 3.3.2-1, #1.d	7. Pressurizer Pressure	S (##) SR 3.3.2.1	24M SR 3.3.2.7	Q SR 3.3.2.4	High ~~and~~ Low (LA.2) (A.30) (A.6)

ITS 3.3.2

SR 3.3.2.1 SR 3.3.2.7 SR 3.3.2.4

TABLE 4.1-1 (Sheet 2 of 6)

	Channel Description	Check	Calibrate	Test	Remarks
SEE 3.3.1	8. 6.9 KV Voltage 6.9 KV Frequency	N.A. N.A.	18M 24M	Q Q	Reactor protection circuits only Reactor protection circuits only
SEE 3.1.7	9. Analog Rod Position	S	24M	M	
T3.3.2-1, #6.b	10. Steam Generator Level	S SR 3.3.2.1	24M SR 3.3.2.7	Q SR 3.3.2.4	A.26
SEE ITS 3.3.3	11. Residual Heat Removal Pump Flow	N.A.	24M	N.A.	
	12. Boric Acid Tank Level	S	24M	N.A.	Bubbler tube rodded during calibration
	13. Refueling Water Storage Tank Level a. Transmitter b. Indicating Switch	W W	18M 6M	N.A. N.A.	Low level alarm Low level alarm
SEE 3.3.3	14a. Containment Pressure - narrow range 14b. Containment Pressure - wide range	S M	24M 18M	Q N.A.	High and High-High A.5 A.12 A.18 A.21
SEE CTS MASTER MARKUP	15. Process and Area Radiation Monitoring:				
	a. Fuel Storage Building Area Radiation Monitor (R-5)	D	24M	Q	SR 3.3.2.4
	b. Vapor Containment Process Radiation Monitors (R-11 and R-12)	D	24M	Q	SR 3.3.2.7 SR 3.3.2.1
	c. Vapor Containment High Radiation Monitors (R-25 and R-26)	D	24M	Q	
	d. Wide Range Plant Vent Gas Process Radiation Monitor (R-27)	D	24M	Q	

Amendment No. 8, 38, 65, 68, 74, 93, 107, 125, 137, 140, 144, 148, 150, 154, 169

T 3.3.2-1, #1.c A.5
" 2.c A.12
" 3.b.3 A.18
" 4.c A.21

T 3.3.2-1, #1.e — A.7
#1.g — A9

SR 3.3.2.1 SR 3.3.2.7 SR 3.3.2.4

TABLE 4.1-1 (Sheet 3 of 6)

Channel Description	Check	Calibrate	Test	Remarks
e. Main Steam Lines Process Radiation Monitors (R-62A, R-62B, R-62C, and R-62D)	D	24M	Q	
f. Gross Failed Fuel Detectors (R-63A and R-63B)	D	24M	Q	
16. Containment Water Level Monitoring System:				
a. Containment Sump	N.A.	24M	N.A.	Narrow Range, Analog
b. Recirculation Sump	N.A.	24M	N.A.	Narrow Range, Analog
c. Containment Water Level	N.A.	24M	N.A.	Wide Range
17. Accumulator Level and Pressure	S	24M	N.A.	
18. Steam Line Pressure	SR 3.3.2.1 S	SR 3.3.2.7 24M	SR 3.3.2.4 Q	A.7 A9
19. Turbine First Stage Pressure	S	24M	Q	A.8 A9 A.22 A.23
20a. Reactor Trip Relay Logic	N.A.	N.A.	TM	
20b. ESF Actuation Relay Logic	N.A.	N.A.	TM	A.27 A.24 A.4 A.11 A.14 A.17 A.20 A.25 A.15
21. Turbine Trip Low Auto Stop Oil Pressure	N.A.	24M	N.A.	
22. DELETED	DELETED	DELETED	DELETED	
23. Temperature Sensor in Auxiliary Boiler Feedwater Pump Building	N.A.	N.A.	18M	
24. Temperature Sensors in Primary Auxiliary Building				
a. Piping Penetration Area	N.A.	N.A.	24M	
b. Mini-Containment Area	N.A.	N.A.	24M	
c. Steam Generator Blowdown Heat Exchanger Room	N.A.	N.A.	24M	

SEE CTS MASTER MARKUP

T 3.3.2-1, Note c

SEE 3.3.1

SEE CTS MASTER MARKUP

SR 3.3.2.2
SR 3.3.2.3
SR 3.3.2.5 → 24 months

T 3.3.2-1, #1.b, 2.b, 3.a.(2), 3.b.(2), 4.b, c.a AND 3.a.3, 5, 6.c

Amendment No. 38, 63, 74, 93, 100, 107, 125, 127, 135, 137, 139, 150, 164, 167, 168, TSCR 98-043

TABLE 4.1-1 (Sheet 4 of 6)

	Channel Description	Check	Calibrate	Test	Remarks
SEE CTS MASTER MARKUP	25. Level Sensors in Turbine Building	N.A.	N.A.	24M	
	26. Volume Control Tank Level	N.A.	24M	N.A.	
	27. Boric Acid Makeup Flow Channel	N.A.	24M	N.A.	
T3.3.2-1, #6.b	28. Auxiliary Feedwater:	SR 3.3.2.1	SR 3.3.2.7	SR 3.3.2.4	SR 3.3.2.6
	a. Steam Generator Level	S	24M	Q	Low-Low
6.d	b. Undervoltage	N.A.	24M	24M	
6.e	c. Main Feedwater Pump Trip	N.A.	N.A.	24M	
SEE CTS MASTER MARKUP	29. Reactor Coolant System Subcooling Margin Monitor	D	24M	N.A.	
	30. PORV Position Indicator	N.A.	N.A.	24M	Limit Switch
	31. PORV Position Indicator	D	24M	24M	Acoustic Monitor
	32. Safety Valve Position Indicator	D	24M	24M	Acoustic Monitor
	33. Auxiliary Feedwater Flow Rate	N.A.	18M	N.A.	
	34. Plant Effluent Radioiodine/ Particulate Sampling	N.A.	N.A.	18M	Sample line common with monitor R-13
	35. Loss of Power				
	a. 480v Bus Undervoltage Relay	N.A.	24M	M	
	b. 480v Bus Degraded Voltage Relay	N.A.	18M	M	
	c. 480v Safeguards Bus Undervoltage Alarm	N.A.	24M	M	
	36. Containment Hydrogen Monitors	D	Q	M	

A.26 A.28 A.29

Amendment No. 38, 44, 54, 65, 67, 74, 93, 125, 136, 137, 142, 144, 150, 168, 169, TSCR 98-043

TABLE 4.1-1 (Sheet 5 of 6)

Channel Description	Check	Calibrate	Test	Remarks
37. Core Exit Thermocouples	D	24M	N.A.	
38. Overpressure Protection System (OPS)	D	18M (1)	18M	1) Calibration frequency for OPS sensors (RCS pressure and temperature) is 24 months
39. Reactor Trip Breakers	N.A.	N.A.	TM(1)	1) Independent operation of under-voltage and shunt trip attachments
			24M(2)	2) Independent operation of under-voltage and shunt trip from Control Room manual push-button
40. Reactor Trip Bypass Breakers	N.A.	N.A.	(1)	1) Manual shunt trip prior to each use
			24M(2)	2) Independent operation of under-voltage and shunt trip from Control Room manual push-button
			24M(3)	3) Automatic undervoltage trip
41. Reactor Vessel Level Indication System (RVLIS)	D	24M	N.A.	
42. Ambient Temperature Sensors Within the Containment Building	D	24M	N.A.	
43. River Water Temperature # (installed)	S	18M	N.A.	1) Check against installed instrumentation or another portable device
44. River Water Temperature # (portable)	S (1)	Q (2)	N.A.	2) Calibrate within 30 days prior to use and quarterly thereafter
45. Steam Line Flow	S SR3.3.2.1	24M SR3.3.2.7	Q SR3.3.2.4	Engineered Safety Features circuits only

SEE CTS MASTER MARKUP

Amendment No. 38, 54, 65, 74, 78, 93, 98, 107, 125, 126, 137, 140, 142, 164, 169, TSCR 98-043

T3.3.2-1, 1.f and 4.d
1.g 4.e

A.8 A.9 A22 A23

ITS 3.3.2

4.5 TESTS FOR ENGINEERED SAFETY FEATURES AND AIR FILTRATION SYSTEMS

A.2

~~Applicability~~

~~Applies to testing of the Safety Injection System, the Containment Spray System, the Hydrogen Recombiner System, and the Air Filtration Systems.~~

~~Objective~~

~~To verify that the subject systems will respond promptly and perform their design functions, if required.~~

Specification

T 3.3.2-1, #1.a

A. SYSTEM TESTS

SR 3.3.2.5
SR 3.3.2.6

1. Safety Injection System

A.3

a. System tests shall be performed at least once per 24 months*. With the Reactor Coolant System pressure less than or equal to 350 psig and temperature less than or equal to 350°F, a test safety injection signal will be applied to initiate operation of the system. The safety injection and residual heat removal pumps are made inoperable for this test.

b. The test will be considered satisfactory if control board indication and visual observations indicate that all components have received the safety injection signal in the proper sequence and timing, that is, the appropriate pump breakers shall have opened and closed, and the appropriate valves shall have completed their travel.

SEE ITS 3.5.2

c. Conduct a flow test of the high head safety injection system after any modification is made to either its piping and/or valve arrangement.

d. Verify that the mechanical stops on Valves 856 A, C, D, E, F, H, J and K are set at the position measured and recorded during the most recent ECCS operational flow test or flow tests performed in accordance with (c) above. This surveillance procedure shall be performed following any maintenance on these valves or their associated motor operators and at a convenient outage if the position of the mechanical stops have not been verified in the preceding three months.

* The time delay relays will be tested at intervals no greater than 22.5 months (18 months + 25%).

2. Containment Spray System

SR 3.3.2.6

A.10

a. System tests shall be performed at least once per 24 months. The tests shall be performed with the isolation valves in the spray supply lines at the containment and the spray additive tank isolation valves blocked closed. Operation of the system is initiated by tripping the normal actuation instrumentation.

b. The spray nozzles shall be checked for proper functioning at least every five years.

SEE ITS MASTER MARKUP

c. The tests will be considered satisfactory if visual observations indicate all components have operated satisfactorily.

3. Containment Hydrogen Monitoring Systems

a. Containment hydrogen monitoring system tests shall be performed at intervals no greater than six months. The tests shall include drawing a sample from the fan cooler units.

b. The above tests will be considered satisfactory if visual observations and control panel indication indicate that all components have operated satisfactorily.

4.7 MAIN STEAM STOP VALVES

~~Applicability~~

A.2

~~Applies to periodic testing of the main steam stop valves.~~

~~Objective~~

~~To verify the ability of the main steam stop valves to close upon signal.~~

Specification T.3.3.2-1, #4a

SR 3.3.2.6

A.19

The main steam stop valves shall be tested at least once per 24 months. Closure time of five seconds or less shall be verified.

SEE ITS 3.7.2

~~Basis~~

~~The main steam stop valves serve to limit an excessive Reactor Coolant System cooldown rate and resultant reactivity insertion following a main steam break incident.[1] Their ability to close upon signal should be verified at least once per 24 months. A closure time of five seconds was selected as being consistent with expected response time for instrumentation as detailed in the steam line break incident analysis.[2]~~

A.1

References

(1) FSAR - Section 10.5

(2) FSAR - Section 14.2.5

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.2:

"Engineered Safety Feature Actuation System (ESFAS) Instrumentation"

PART 3:

DISCUSSION OF CHANGES

Differences between CTS and ITS

DISCUSSION OF CHANGES
ITS SECTION 3.3.2 - ENGINEERED SAFETY FEATURE ACTUATION SYSTEM (ESFAS) INSTRUMENTATION

ADMINISTRATIVE

A.1 In the conversion of the Indian Point Unit 3 Current Technical Specifications (CTS) to the plant specific Improved Technical Specifications (ITS) certain wording preferences or conventions are adopted which do not result in technical changes (either actual or interpretational). Additionally, editorial changes, reformatting, and revised numbering are adopted to make ITS consistent with the conventions in NUREG-1431, Standard Technical Specifications, Westinghouse Plants, Rev. 1, i.e., the improved Standard Technical Specifications.

The CTS Bases are deleted and replaced with comprehensive ITS Bases designed to support interpretation and implementation of the associated Technical Specifications. The Bases explain, clarify, and document the reasons (i.e., bases) for the associated Technical Specifications, and reflect the IP3 plant specific design, analyses, and licensing basis. In accordance with 10 CFR 50.36(a), the ITS Bases are included with the proposed ITS conversion application; however, deletion of the CTS Bases and the adoption of the ITS Bases is an administrative change with no impact on safety.

A.2 CTS Limiting Conditions for Operation (LCOs) and Surveillance Requirements (SRs) include statements of the objective and the applicability. The CTS statements of objective and applicability are deleted because these statements do not establish any requirements and do not provide any guidance for the application of CTS requirements. Therefore, deletion of these statements has no significant adverse impact on safety.

A.3 **ITS 3.3.2, Function 1.a., Safety Injection-Manual Initiation,** is equivalent to CTS Table 3.5-3, Item 1.a. (Safety Injection) Manual. The ITS conversion modifies the CTS requirements as follows:

DISCUSSION OF CHANGES
ITS SECTION 3.3.2 - ENGINEERED SAFETY FEATURE ACTUATION SYSTEM (ESFAS) INSTRUMENTATION

a. CTS 3.5.1 establishes the Applicability for Engineered Safety Features initiation instrumentation as whenever the plant is not in the cold shutdown condition. ITS requires this function operable in Modes 1, 2, 3 and 4 (i.e., above cold shutdown). Therefore, there is no change to the existing Applicability.

b. CTS Table 3.5-3 requires 1 operable channel with a minimum degree of redundancy of zero (See ITS 3.3.2, DOC A.34) for the manual initiation function. ITS 3.3.2 requires 2 operable channels for the manual initiation function. This is a more restrictive change (See 3.3.2, DOC M.1).

c. For a loss of redundancy for the manual trip capability, 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 the manual initiation function (See 3.3.2, DOC M.1). Under the same conditions, ITS LCO 3.3.2, Action B.1, will require that if one of the two required channels is inoperable (i.e., loss of redundancy but no loss of function) then both channels must be made Operable within 48 hours. This AOT was justified in WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990 (See 3.3.2, DOC L.3).

For a loss of function for the manual trip capability, CTS Table 3.5-3, Note 6, requires that the plant be placed in hot shutdown (Mode 3) within the next 4 hours and cold shutdown (Mode 5) within 48 hours (unless Applicable condition is exited by shutting the MSIVs). Under the same conditions (loss of manual initiation function), ITS LCO 3.3.2 does not specify a Condition and defaults to LCO 3.0.3. LCO 3.0.3 requires that a plant shutdown be initiated within one hour and the plant be in Mode 3 within 7 hours (versus 4 hours in CTS, See ITS 3.3.2, Doc L.5) and Mode 5 within 37 hours (versus 48 hours in CTS, See ITS 3.3.2, DOC M.5).

d. CTS Table 4.1-1 does not establish a specific requirement to test the Safety Injection Manual Initiation Function: however, CTS

4.5.A.1.a establishes requirements for testing the Safety Injection Function every 24 months. ITS SR 3.3.2.6 maintains the same requirement to verify Operability of the manual initiation function by the performance of a Trip Actuating Device Operational Test (TADOT) every 24 months. The SR is modified by a Note that excludes verification of setpoints during the TADOT for manual initiation Functions because these Functions have no associated setpoints.

Note that CTS 4.5.A.1.a and CTS 4.6.A.3 include a footnote requiring that the Safety Injection Timers be tested every 18 months. Requirements for these timers are included in ITS LCO 3.8.1, AC Sources, because the purpose of these timers is to protect the AC source from overloading during a Safety Injection starting sequence. (See ITS 3.8.1, DOC L.6).

e. There is no allowable value or setpoint associated with this function.

f. Confirmation of the applicability of WCAP-10271 to the Indian Point 3 design and operation has already been confirmed by NYPA and reviewed by the NRC as part of Technical Specification Amendment 107, dated March 22, 1991.

Except as noted above, each of the changes described above is an administrative change with no adverse impact on safety.

A.4 **ITS 3.3.2, Function 1.b. Safety Injection-Automatic Actuation Logic and Actuation Relays**, is not listed in the CTS as a required Function but is implicitly required to be Operable to support the Operability of all ESFAS Safety Injection Functions (i.e., manual initiation, containment high pressure, pressurizer low pressure, etc.). ITS 3.3.2, Function 1.b. applies to those portions of the ESFAS Safety Injection circuit that are: 1) common to more than one channel in one train of a single function (i.e., the automatic actuation logic); or, 2) the initiating

relay contacts in one train responsible for actuating the ESF equipment (i.e., the Actuation Relays) which are common to both more than one channel of a single function and more than one function. There are two trains of Safety Injection-Automatic Actuation Logic and Actuation Relays.

This change is needed because it establishes Conditions and Required Actions that address inoperabilities that are: 1) common to more than one channel of a single function; or, 2) affect the initiating relay contacts responsible for actuating the ESF equipment. The ITS conversion modifies the CTS requirements as follows:

a. CTS 3.5.1 establishes the Applicability for Engineered Safety Features initiation instrumentation as whenever the plant is not in the cold shutdown condition. ITS requires this function operable in Modes 1, 2, 3 and 4 (i.e., above cold shutdown). Therefore, there is no change to the existing Applicability.

b. CTS Table 3.5-3 implicitly requires 2 operable trains with a minimum degree of redundancy of 1 train (See ITS 3.3.2, DOC A.34) for this function because this configuration is necessary to meet the minimum degree of redundancy requirements for each of the associated ESFAS functions. This combination enforces an unstated requirement that an inoperable train be restored to Operable because with two trains there is no way to re-establish the required redundancy and placing an inoperable train in trip causes an ESFAS actuation. ITS 3.3.2, Function 1.b, establishes the requirement for minimum operable channels as "2 trains" and associated Required Action C.1 requires that an inoperable channel be restored to Operable. Therefore, there is no change to the existing requirements for minimum number of operable channels or minimum degree of redundancy.

c. For a loss of redundancy or a loss of function for Automatic Actuation Logic and Actuation Relays, CTS Table 3.5-3, Note 6, requires that an inoperable train must be restored to Operable

immediately or the plant be placed in hot shutdown (Mode 3) within the next 4 hours and cold shutdown (Mode 5) within 48 hours of discovery of the inoperable condition. Under the same conditions, ITS 3.3.2 differentiates between one inoperable train (loss of redundancy) and two inoperable trains (loss of function).

For the loss of redundancy (i.e., one train inoperable), ITS 3.3.2, Required Action C.1, allows 6 hours to restore the train to Operable. This AOT was justified in WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990 (See 3.3.2, DOC L.3). If redundancy is not restored within the AOT, ITS 3.3.2, Required Action C.2.1 and C.2.2, require the plant be in Mode 3 in the following 6 hours (versus 4 hours in CTS, See ITS 3.3.2, Doc L.5) and Mode 5 in the 36 hours (versus 48 hours in CTS, See ITS 3.3.2, DOC M.5).

For a loss of function (i.e., both trains inoperable), ITS LCO 3.3.2 does not specify a Condition and defaults to LCO 3.0.3. LCO 3.0.3 requires that a plant shutdown be initiated within one hour and the plant be in Mode 3 within 7 hours (versus 4 hours in CTS, See ITS 3.3.2, Doc L.5) and Mode 5 within 37 hours (versus 48 hours in CTS, See ITS 3.3.2, DOC M.5).

d. CTS Table 4.1-1, Item 20.b, requires a test of "ESF Actuation Relay Logic" at the TM Frequency (i.e., every two months on a staggered test basis). ITS SR 3.3.2.2, Actuation Logic Test, and ITS SR 3.3.2.3, Master Relay Test, maintain the requirement for testing the automatic actuation logic and actuation relays, respectively, at the same Frequency.

Slave relay operation causes equipment to actuate and CTS Table 4.1-1, Item 20.b, is not interpreted as requiring testing of the slave relays. The slave relays are currently tested every 24 months as required by CTS 4.5.A.1.a. ITS SR 3.3.2.5, Slave Relay Test, establishes a requirement to verify operability of the slave relays every 24 months, which is consistent with CTS 4.5.A.1 requirements to test the Safety Injection System.

CTS allowances for bypassing channels and deferring entry into Conditions and Required Actions during testing are maintained (See ITS 3.3.2, DOC A.36).

e. There is no allowable value or setpoint associated with this function.

f. Confirmation of the applicability of WCAP-10271 to the Indian Point 3 design and operation has already been confirmed by NYPA and reviewed by the NRC as part of Technical Specification Amendment 107, dated March 22, 1991.

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated justification.

A.5 **ITS 3.3.2, Function 1.c, Safety Injection-Containment Pressure-High**, is equivalent to CTS Table 3.5-1, Item 1, and CTS Table 3.5-3, Item 1.b. (Safety Injection) High Containment Pressure (Hi). The ITS conversion modifies the CTS requirements as follows:

a. CTS 3.5.1 establishes the Applicability for Engineered Safety Features initiation instrumentation as whenever the plant is not in the cold shutdown and CTS Table 3.5-3 establishes an implied Applicability for this by requiring that the plant be in cold shutdown (Mode 5) if requirements cannot be met. However, CTS 3.5.8 specifies that a minimum of two channels must be operable when Tavg is greater than 350°F.

ITS requires this function operable in Modes 1, 2 and 3 (i.e., Tavg ≥ 350°F). Although ITS Applicability requirements are consistent with CTS 3.5.8, this is a less restrictive change because ITS 3.3.2 will no longer require automatic initiation capability for Safety Injection in Mode 4 (See 3.3.2, DOC L.4).

b. CTS Table 3.5-3 specifies that the IP3 design includes 3 channels and that 2 channels are required to trip. CTS Table 3.5-3 requires 2 operable channels with a minimum degree of redundancy of 1 (See ITS 3.3.2, DOC A.34). This combination creates a requirement for 3 Operable channels with no more than 1 channel in trip and enforces an unstated requirement that an inoperable channel be placed in trip. This is consistent with CTS 3.5.8 (two channels must be operable, i.e., one channel may be in trip).

ITS 3.3.2, Function 1.c, restates the requirement for minimum operable channels as 3 and associated Required Action D.1 requires that an inoperable channel be tripped. Therefore, there is no change to the existing requirements for minimum number of operable channels or minimum degree of redundancy.

c. For a loss of redundancy (one channel inoperable and not in trip) or a loss of function (more than one channel inoperable), CTS Table 3.5-3, Note 6, requires that an inoperable channel must be restored to Operable immediately or the plant be placed in hot shutdown (Mode 3) within the next 4 hours and cold shutdown (Mode 5) within 48 hours of discovery of the inoperable condition.

Under the same conditions, ITS 3.3.2 differentiates between one inoperable channel not in trip (loss of redundancy) and two inoperable channels not in trip (potential loss of function).

For a loss of redundancy for this function, CTS Table 3.5-3, Note 6, requires that an inoperable channel be tripped immediately. Under the same conditions, ITS LCO 3.3.2, Action D.1, allows 6 hours to place the inoperable channel in trip. This AOT was justified in WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990 (See 3.3.2, DOC L.3).

For a loss of redundancy where the required redundancy is not restored by placing the inoperable channel in trip within the AOT, ITS LCO 3.3.2, Required Action D.2.1 and D.2.2, require the plant

be in Mode 3 in the following 6 hours (versus 4 hours in CTS, See ITS 3.3.2, Doc L.5) and Mode 4 in 18 hours (See ITS 3.3.2, DOC L.4 for change in the Applicability).

For a potential loss of function (i.e., more than one channel inoperable), ITS LCO 3.3.2 does not specify a Condition and defaults to LCO 3.0.3. LCO 3.0.3 requires that a plant shutdown be initiated within one hour and the plant be in Mode 3 within 7 hours (versus 4 hours in CTS, See ITS 3.3.2, Doc L.5) and Mode 4 within 13 hours (See ITS 3.3.2, DOC L.4 for change in the Applicability).

d. CTS Table 4.1-1, Item 14,a, Containment Pressure-Narrow Range, requires a channel check every shift, a channel test every quarter, and a channel calibration every 24 months. ITS SR 3.3.2.1 requires a channel check every 12 hours which maintains the existing requirement and Frequency. ITS SR 3.3.2.4 requires a channel operational test (COT) every 92 days which maintains the existing requirement and Frequency. And, ITS SR 3.3.2.7 requires a channel calibration every 24 months which maintains the existing requirement and Frequency. Therefore, there is no change to the CTS Surveillance requirements for Frequency.

CTS allowances for bypassing channels and deferring entry into Conditions and Required Actions during testing are maintained (See ITS 3.3.2, DOC A.36).

e. CTS Table 3.5-1, Item 1, establishes the allowable value for the (Safety Injection) High Containment Pressure (Hi Level) at $\leq$ 4.5 psig. ITS 3.3.2, Function 1.c, Safety Injection-Containment Pressure-High, establishes the allowable value at $\leq$ 4.80 psig because ITS uses allowable values calculated in accordance with Engineering Standards Manual IES-3 and IES-3B, Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3) (See ITS 3.3.1, DOC L.1).

f. Confirmation of the applicability of WCAP-10271 to the Indian Point 3 design and operation has already been confirmed by NYPA and reviewed by the NRC as part of Technical Specification Amendment 107, dated March 22, 1991.

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated justification.

A.6 **ITS 3.3.2, Function 1.d, Safety Injection-Pressurizer Pressure-Low,** is equivalent to CTS Table 3.5-1, Item 3, and CTS Table 3.5-3, Item 1.d. (Safety Injection) Pressurizer Low Pressure. The ITS conversion modifies the CTS requirements as follows:

a. CTS 3.5.1 establishes the Applicability for Engineered Safety Features initiation instrumentation as whenever the plant is not in the cold shutdown condition and CTS 3.5.5 and CTS Table 3.5-3, Note 3, requires that low pressurizer pressure safety injection trip be unblocked when the pressurizer pressure is $\geq$ 2000 psig. ITS requires this function operable in Modes 1, 2 and 3 when above the Pressurizer Pressure interlock. Therefore, there is no change to the existing Applicability.

b. CTS Table 3.5-3 specifies that the IP3 design includes 3 channels and that 2 channels are required to trip. CTS Table 3.5-3 requires 2 operable channels with a minimum degree of redundancy of 1 (See ITS 3.3.2, DOC A.34). This combination creates a requirement for 3 Operable channels with no more than 1 channel in trip and enforces an unstated requirement that an inoperable channel be placed in trip. This is consistent with CTS 3.5.8 (two channels must be operable, i.e., one channel may be in trip).

ITS 3.3.2, Function 1.d, restates the requirement for minimum operable channels as 3 and associated Required Action D.1 requires that an inoperable channel be tripped. Therefore, there is no change to the existing requirements for minimum number of operable

channels or minimum degree of redundancy.

c. For a loss of redundancy (one channel inoperable and not in trip) or a loss of function (more than one channel inoperable), CTS Table 3.5-3, Note 6, requires that an inoperable channel must be restored to Operable immediately or the plant be placed in hot shutdown (Mode 3) within the next 4 hours and cold shutdown (Mode 5) within 48 hours of discovery of the inoperable condition.

Under the same conditions, ITS 3.3.2 differentiates between one inoperable channel not in trip (loss of redundancy) and two inoperable channels not in trip (potential loss of function).

For a loss of redundancy for this function, CTS Table 3.5-3, Note 6, requires that an inoperable channel be tripped immediately. Under the same conditions, ITS LCO 3.3.2, Action D.1, allows 6 hours to place the inoperable channel in trip. This AOT was justified in WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990 (See 3.3.2, DOC L.3).

For a loss of redundancy where the required redundancy is not restored by placing the inoperable channel in trip within the AOT, ITS LCO 3.3.2, Required Action D.2.1 and D.2.2, require the plant be in Mode 3 in the following 6 hours (versus 4 hours in CTS, See ITS 3.3.2, Doc L.5) and Mode 4 in 18 hours (See ITS 3.3.2, DOC L.4 for change in the Applicability). Note that both CTS and ITS require only that the plant be placed outside the applicability for Function 1.d, Safety Injection-Pressurizer Pressure-Low, (i.e., Mode 3 with pressure reduced to below the Pressurizer Pressure interlock setpoint).

For a potential loss of function (i.e., more than one channel inoperable), ITS LCO 3.3.2 does not specify a Condition and defaults to LCO 3.0.3. LCO 3.0.3 requires that a plant shutdown be initiated within one hour and the plant be in Mode 3 within 7 hours (versus 4 hours in CTS, See ITS 3.3.2, Doc L.5) and Mode 4

within 13 hours (See ITS 3.3.2, DOC L.4 for change in the Applicability).

d. CTS Table 4.1-1, Item 7, Pressurizer Pressure, requires a channel check every shift, a channel test every quarter, and a channel calibration every 24 months. ITS SR 3.3.2.1 requires a channel check every 12 hours which maintains the existing requirement and Frequency; ITS SR 3.3.2.4 requires a channel operational test every 92 days which maintains the existing requirement and Frequency; and, ITS SR 3.3.2.7 requires a channel calibration every 24 months which maintains the existing requirement and Frequency. Therefore, there is no change to the CTS Surveillance requirements or the associated Frequency.

   CTS allowances for bypassing channels and deferring entry into Conditions and Required Actions during testing are maintained (See ITS 3.3.2, DOC A.36).

e. CTS Table 3.5-1, Item 3, establishes the allowable value for Pressurizer Low Pressure at ≥1700 psig. ITS 3.3.2, Function 1.d, Safety Injection-Pressurizer Pressure-Low, establishes the allowable value at ≥1684.64 psig because ITS uses allowable values calculated in accordance with Engineering Standards Manual IES-3 and IES-3B, Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3) (See ITS 3.3.1, DOC L.1).

f. Confirmation of the applicability of WCAP-10271 to the Indian Point 3 design and operation has already been confirmed by NYPA and reviewed by the NRC as part of Technical Specification Amendment 107, dated March 22, 1991.

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated justification.

A.7 **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, and CTS Table 3.5-3, Item 1.c. (Safety Injection) High Differential Pressure Between Steam Lines. The ITS conversion modifies the CTS requirements as follows:

a. CTS 3.5.1 establishes the Applicability for Engineered Safety Features initiation instrumentation as whenever the plant is not in the cold shutdown condition. ITS requires this function operable in Modes 1, 2 and 3 (i.e., Tavg ≥ 350°F). This is a less restrictive change because ITS 3.3.2 does not require automatic initiation capability for Safety Injection in Mode 4 (See 3.3.2, DOC L.4).

b. CTS Table 3.5-3 specifies that the IP3 design includes 3 channels per steam line and that 2 channels per steam line in any steam line will cause actuation. CTS Table 3.5-3 requires 2 operable channels in each steam line with a minimum degree of redundancy of 1 channel per steam line. This combination creates a requirement for 3 channels per steam line with no more than 1 channel per steam line in trip and enforces an unstated requirement that an inoperable channel be placed in trip (See ITS 3.3.2, DOC A.34).

ITS 3.3.2, Function 1.e, restates the requirement for minimum operable channels as 3 channels per steam line and associated Required Action D.1 requires that an inoperable channel be tripped. Therefore, there is no change to the existing requirements for minimum number of operable channels or minimum degree of redundancy.

c. (See ITS 3.3.2, DOC A.5.c for a discussion of Required Actions.)

d. CTS Table 4.1-1, Item 18, Steam Line Pressure, requires a channel check every shift, a channel test every quarter, and a channel calibration every 24 months. ITS SR 3.3.2.1 requires a channel

check every 12 hours which maintains the existing requirement and Frequency; ITS SR 3.3.2.4 requires a channel operational test every 92 days which maintains the existing requirement and Frequency; and, ITS SR 3.3.2.7 requires a channel calibration every 24 months which maintains the existing requirement and Frequency. Therefore, there is no change to the CTS Surveillance requirements or the associated Frequency.

CTS allowances for bypassing channels and deferring entry into Conditions and Required Actions during testing are maintained (See ITS 3.3.2, DOC A.36).

e. CTS Table 3.5-1, Item 4, (Safety Injection) High Differential Pressure Between Steam Lines. establishes the allowable value at ≤150 psi. ITS 3.3.2, Function 1.e, Safety Injection-High Differential Pressure Between Steam Lines, establishes the allowable value at ≤208 psi because ITS uses allowable values calculated in accordance with Engineering Standards Manual IES-3 and IES-3B, Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3) (See ITS 3.3.1, DOC L.1).

f. Confirmation of the applicability of WCAP-10271 to the Indian Point 3 design and operation has already been confirmed by NYPA and reviewed by the NRC as part of Technical Specification Amendment 107, dated March 22, 1991.

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated justification.

A.8 **ITS 3.3.2, Function 1.f. Safety Injection-High Steam Flow in Two Steam Lines Coincident with Tavg-Low**, is equivalent to CTS Table 3.5-1, Item 5.a, and CTS Table 3.5-3, Item 1.e.1 (Safety Injection) High Steam Flow in 2/4 Steam Lines Coincident with Low Tavg. The ITS conversion modifies the CTS requirements as follows:

a. CTS 3.5.1 establishes the Applicability for Engineered Safety Features initiation instrumentation as whenever the plant is not in the cold shutdown condition and CTS Table 3.5-3 establishes an implied Applicability by requiring either plant be in cold shutdown (Mode 5) or all MSIVs closed if requirements cannot be met. ITS 3.3.2 requires this function operable in Mode 1 and in Modes 2 and 3 unless all MSIVs are closed. This is a less restrictive change because ITS 3.3.2 does not require automatic initiation capability for Safety Injection in Mode 4 (See 3.3.2, DOC L.4).

b. For the High Steam Flow Function, the IP3 design consists of 2 channels per steam line of high steam flow and 1 channel per steam line in any 2 steam lines is sufficient for actuation. CTS Table 3.5-3 requires 1 channel per steam line in each of three steam lines and a minimum degree of redundancy of 1 channel per steam line in each of three steam lines. ITS 3.3.2, Function 1.f, restates the requirement for minimum operable channels as 2 per steam line (on all four steam lines) and associated Required Action D.1 requires that an inoperable channel be placed in trip. Requiring 2 channels per steam line on all 4 steam lines (versus the CTS requirement for 3 of 4 steam lines) is a more restrictive change (See 3.2.2, DOC M.2).

For the Tavg-Low Function, the IP3 design consists of 1 channel per loop of Tavg and 1 channel in any 2 loops is sufficient for actuation. CTS Table 3.5-3 requires 3 channels with a minimum degree of redundancy of 2. This combination creates a requirement for 1 channel per loop (i.e., 4 channels) with no more than 1 channel in trip and enforces an unstated requirement that an inoperable channel be placed in trip. ITS 3.3.2, Function 1.f, restates the requirement for minimum operable channels as 1 per loop and associated Required Action D.1 requires that an inoperable channel be placed in trip. Therefore, there is no change to the existing requirements for minimum number of operable channels or minimum degree of redundancy (for the Tavg portion of

this Functional).

c. For a loss of redundancy (one channel of steam flow and/or Tavg inoperable and not in trip) or a loss of function (more than one channel inoperable of steam flow and/or Tavg), CTS Table 3.5-3, Note 6, requires that an inoperable channel must be restored to Operable immediately or the plant be placed in hot shutdown (Mode 3) within the next 4 hours and cold shutdown (Mode 5) within 48 hours of discovery of the inoperable condition.

Under the same conditions, ITS 3.3.2 differentiates between one inoperable channel not in trip (loss of redundancy) and two inoperable channels not in trip (potential loss of function).

For a loss of redundancy for this function, CTS Table 3.5-3, Note 6, requires that an inoperable channel be tripped immediately. Under the same conditions, ITS LCO 3.3.2, Action D.1, allows 6 hours to place the inoperable channel in trip. This AOT was justified in WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990 (See 3.3.2, DOC L.3).

For a loss of redundancy where the required redundancy is not restored by placing the inoperable channel in trip within the AOT, ITS LCO 3.3.2, Required Action D.2.1 and D.2.2, require the plant be in Mode 3 in the following 6 hours (versus 4 hours in CTS, See ITS 3.3.2, Doc L.5) and Mode 4 in 18 hours (See ITS 3.3.2, DOC L.4 for change in the Applicability). Note that both CTS and ITS require only that the plant be placed outside the applicability for Function 1.f. Safety Injection-High Steam Flow in Two Steam Lines Coincident with Tavg-Low, which can be achieved by closing all of the MSIVs even if the plant remains in Mode 2 or 3.

For a potential loss of function (i.e., more than one channel of steam flow and/or Tavg inoperable), ITS LCO 3.3.2 does not specify a Condition and defaults to LCO 3.0.3. LCO 3.0.3 requires that a plant shutdown be initiated within one hour and the plant be in

Mode 3 within 7 hours (versus 4 hours in CTS, See ITS 3.3.2, Doc L.5) and Mode 4 within 13 hours (See ITS 3.3.2, DOC L.4 for change in the Applicability).

d. CTS Table 4.1-1, Item 4, Reactor Coolant Temperature, CTS Table 4.1-1, Item 18, Steam line Pressure, CTS Table 4.1-1, Item 45, Steam Flow, and CTS Table 4.1-1, Item 19, Turbine First Stage Pressure (This is the input to the Steam Flow Setpoint Adjustment), each require a channel check every shift, a channel test every quarter, and a channel calibration every 24 months. ITS SR 3.3.2.1 requires a channel check every 12 hours which maintains the existing requirement and Frequency; ITS SR 3.3.2.4 requires a channel operational test every 92 days which maintains the existing requirement and Frequency; and, ITS SR 3.3.2.7 requires a channel calibration every 24 months which maintains the existing requirement and Frequency. Therefore, there is no change to the CTS Surveillance requirements or the associated Frequency.

CTS allowances for bypassing channels and deferring entry into Conditions and Required Actions during testing are maintained (See ITS 3.3.2, DOC A.36).

e. CTS Table 3.5-1, Item 5, Safety Injection-High Steam Flow in 2/4 Steam Lines Coincident with Low Tavg. establishes allowable values for steam flow at ≤ 49% of full steam flow at zero load, ≤ 49% of full steam flow at 20% load, and ≤ 110% of full steam flow at full load. Establishing allowable values for this Function requires an allowable value for the steam flow instruments and an allowable value for the turbine first stage pressure which adjusts the steam flow setpoint. CTS Table 3.5-1, Item 5, establishes allowable value for low Tavg at ≥ 540°F.

ITS 3.3.2, Function 1.f, establishes the allowable value for steam flow at less than or equal to turbine first stage pressure corresponding to 54.4% full steam flow below 20% load, and increasing linearly from 54.4% full steam flow at 20% load to 110%

full steam flow at 100% load, and corresponding to 110% full steam flow above 100% load. ITS 3.3.2, Function 1.f, establishes the allowable value for low Tavg at ≥ 535.6°F. These changes to the allowable values were calculated in accordance with Engineering Standards Manual IES-3 and IES-3B, Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3) (See ITS 3.3.1, DOC L.1).

f. Confirmation of the applicability of WCAP-10271 to the Indian Point 3 design and operation has already been confirmed by NYPA and reviewed by the NRC as part of Technical Specification Amendment 107, dated March 22, 1991. However, to conform to the assumptions of WCAP-10271, ITS 3.3.2, Function 1.f will increase requirements for steam flow channels to require 2 channels per steam line on all 4 steam lines (versus the CTS requirement for 3 of 4 steam lines) (See 3.2.2, DOC M.2).

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated justification.

A.9 **ITS 3.3.2, Function 1.g. Safety Injection-High Steam Flow in Two Steam Lines Coincident with Steam Line Pressure-Low**, is equivalent to CTS Table 3.5-1, Item 5, and CTS Table 3.5-3, Item 1.e.2 (Safety Injection) High Steam Flow in 2/4 Steam Lines Coincident with Low Tavg. The ITS conversion changes from the CTS requirements for this Function are identical to those described for ITS 3.3.2, Function 1.f. Safety Injection-High Steam Flow in Two Steam Lines Coincident with Tavg-Low (See 3.3.2, DOC A.8) except as described below:

a. (See 3.3.2, DOC A.8.a)

b. (See 3.3.2, DOC A.8.b. Discussion is identical except that steam line pressure replaces Tavg.)

c. (See 3.3.2, DOC A.8.c)

d. (See 3.3.2, DOC A.8.d for the Steam Flow portion of this Function) CTS Table 4.1-1, Item 18, Steam line Pressure, requires a channel check every shift, a channel test every quarter, and a channel calibration every 24 months. ITS SR 3.3.2.1 requires a channel check every 12 hours which maintains the existing requirement and Frequency; ITS SR 3.3.2.4 requires a channel operational test every 92 days which maintains the existing requirement and Frequency; and, ITS SR 3.3.2.7 requires a channel calibration every 24 months which maintains the existing requirement and Frequency. Therefore, there is no change to the CTS Surveillance requirements or the associated Frequency.

CTS allowances for bypassing channels and deferring entry into Conditions and Required Actions during testing are maintained (See ITS 3.3.2, DOC A.36).

e. (See 3.3.2, DOC A.8.e for the Steam Flow portion of this Function) Additionally, CTS Table 3.5-1, Item 5, Safety Injection) High Steam Flow in 2/4 Steam Lines Coincident with Low Steam Line Pressure establishes allowable for Low Steam Line Pressure at $\geq$ 600 psig. ITS 3.3.2, Function 1.g, establishes the allowable value for low steam line pressure at $\geq$ 476 psig.. These changes to the allowable values were calculated in accordance with Engineering Standards Manual IES-3 and IES-3B, Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3) (See ITS 3.3.1, DOC L.1).

f. (See 3.3.2, DOC A.8.f)

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated justification.

A.10 **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. The ITS conversion modifies the CTS requirements as follows:

a. CTS 3.5.1 establishes the Applicability for Engineered Safety Features initiation instrumentation as whenever the plant is not in the cold shutdown condition. ITS requires this function operable in Modes 1, 2, 3 and 4 (i.e., above cold shutdown). Therefore, there is no change to the existing Applicability.

b. CTS Table 3.5-3 requires 2 operable channels with a minimum degree of redundancy of zero. ITS 3.3.2 requires 2 channels per train and 2 trains. Both CTS (i.e., Table 3.5-3, Note 4) and ITS recognize and require the following: manual initiation of containment spray (CS) requires that two pushbuttons in the control room be depressed simultaneously to actuate both trains of CS. Each CS pushbutton closes one of the two contacts required to start CS train A and one of the two contacts required to start CS train B; depressing both pushbuttons closes both of the contacts required to start CS train A and both of the contacts required to start CS train B. Both CTS and ITS require that two contacts be Operable for CS train A and two contacts are required to be Operable for CS train B. Therefore, there is no change to the existing requirements except that the CTS defines both of the contacts required to start a train as one channel and ITS defines each of the contacts required to start a train as a separate channel. This is an administrative change because the interpretation of the CTS is consistent with the requirements imposed by the ITS.

c. For a loss of redundancy for the manual trip capability, 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 the manual initiation function (See ITS 3.3.2, DOC A.10.b). Under the same conditions, ITS LCO 3.3.2, Action B.1, will require that if one of the two required channels is inoperable (i.e., loss of redundancy but no loss of function) then both channels must be made Operable within 48 hours. This AOT was justified in WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990 (See 3.3.2, DOC L.3).

For a loss of function for the manual trip capability, CTS Table 3.5-3, Note 6, requires that the plant be placed in hot shutdown (Mode 3) within the next 4 hours and cold shutdown (Mode 5) within 48 hours. Under the same conditions (loss of manual initiation function), ITS LCO 3.3.2 does not specify a Condition and defaults to LCO 3.0.3. LCO 3.0.3 requires that a plant shutdown be initiated within one hour and the plant be in Mode 3 within 7 hours (versus 4 hours in CTS, See ITS 3.3.2, Doc L.5) and Mode 5 within 37 hours (versus 48 hours in CTS, See ITS 3.3.2, DOC M.5).

d. CTS Table 4.1-1 does not establish a specific requirement to test the Containment Spray Manual Initiation Function: however, CTS 4.5.A.2.a establishes requirements for testing the Containment Spray Function every 24 months. ITS SR 3.3.2.6 maintains the same requirement to verify Operability of the manual initiation function by the performance of a Trip Actuating Device Operational Test (TADOT) every 24 months. The SR is modified by a Note that excludes verification of setpoints during the TADOT for manual initiation Functions because these Functions have no associated setpoints.

e. There is no allowable value or setpoint associated with this function.

f. Confirmation of the applicability of WCAP-10271 to the Indian Point 3 design and operation has already been confirmed by NYPA and reviewed by the NRC as part of Technical Specification Amendment 107, dated March 22, 1991.

Except as noted above, each of the changes described above is an administrative change with no adverse impact on safety.

A.11 **ITS 3.3.2, Function 2.b. Automatic Actuation Logic and Actuation Relays,** is not listed in the CTS as a required Function but is implicitly required to be Operable to support the Operability of all ESFAS

Containment Spray Functions (i.e., manual initiation, containment high pressure, etc.). (See ITS 3.3.2, DOC A.4 for the discussion of Automatic Actuation Logic and Actuation Relays.)

A.12 **ITS 3.3.2, Function 2.c. Containment Pressure (High High)**, is equivalent to CTS Table 3.5-1, Item 2, and CTS Table 3.5-3, Item 2.b. (Containment Spray) High Containment Pressure (Hi Hi Level). The ITS conversion modifies the CTS requirements as follows:

a. CTS 3.5.1 establishes the Applicability for Engineered Safety Features initiation instrumentation as whenever the plant is not in the cold shutdown condition. ITS requires this function operable in Modes 1, 2 and 3 (i.e., Tavg ≥ 350°F). This is a less restrictive change because ITS 3.3.2 does not require automatic initiation capability for Containment Spray in Mode 4 (See 3.3.2, DOC L.4).

b. For the High Containment Pressure (Hi Hi Level) Function, the IP3 design consists of 2 sets of 3 channels and 2 channels from each set of 3 are required to energize to actuate Containment Spray. CTS Table 3.5-3 requires 2 channels per set to be Operable with a minimum degree of redundancy of 1 channel per set. This combination creates a requirement for 2 sets of 3 channels with no more than 1 channel in each set in trip and enforces an unstated requirement that an inoperable channel be placed in trip.

   ITS 3.3.2, Function 2.c, restates the requirement for minimum operable channels as 2 sets of 3 channels and associated Required Action E.1 requires that an inoperable channel be tripped. Therefore, there is no change to the existing requirements for minimum number of operable channels or minimum degree of redundancy.

c. For a loss of redundancy for this function, CTS Table 3.5-3, Note 6, requires that an inoperable channel be tripped

immediately. Under the same conditions, ITS LCO 3.3.2, Action E.1, allows 6 hours to place the inoperable channel in trip. This AOT was justified in WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990 (See 3.3.2, DOC L.3).

For a loss of redundancy where the required redundancy is not restored by placing the inoperable channel in trip within the AOT, ITS LCO 3.3.2, Required Action E.2.1 and E.2.2, require the plant be in Mode 3 in the following 6 hours (versus 4 hours in CTS, See ITS 3.3.2, Doc L.5) and Mode 4 in 18 hours (See ITS 3.3.2, DOC L.4 for change in the Applicability).

For a loss of function (i.e., more than one channel inoperable in one or both sets of three), ITS LCO 3.3.2 does not specify a Condition and defaults to LCO 3.0.3. LCO 3.0.3 requires that a plant shutdown be initiated within one hour and the plant be in Mode 3 within 7 hours (versus 4 hours in CTS, See ITS 3.3.2, Doc L.5) and Mode 4 within 13 hours (See ITS 3.3.2, DOC L.4 for change in the Applicability).

CTS Table 3.5-3, Item 2.b. Note 8, specifies that only MSIVs need be closed if the only portion of the circuit affected is MSIV closure circuitry. Note 8 provides recognition that the same containment high pressure transmitters are used for both MSIV isolation and containment spray. This note is not needed in either CTS or ITS because if containment high pressure transmitters are inoperable, then Required Actions for both the steam line isolation and containment spray are applicable. If the inoperability affects only steam line isolation or containment spray, then only the Required Actions associated with the inoperable function are required.

d. CTS Table 4.1-1, Item 14.a, Containment Pressure-Narrow Range, requires a channel check every shift, a channel test every quarter, and a channel calibration every 24 months. ITS SR 3.3.2.1 requires a channel check every 12 hours which maintains

the existing requirement and Frequency: ITS SR 3.3.2.4 requires a channel operational test every 92 days which maintains the existing requirement and Frequency: and, ITS SR 3.3.2.7 requires a channel calibration every 24 months which maintains the existing requirement and Frequency. Therefore, there is no change to the CTS Surveillance requirements or the associated Frequency.

CTS allowances for bypassing channels and deferring entry into Conditions and Required Actions during testing are maintained (See ITS 3.3.2, DOC A.36).

e. CTS Table 3.5-1, Item 2, High Containment Pressure (Hi Hi Level). establishes allowable value at ≤ 24 psig. ITS 3.3.2, Function 2.c, establishes the allowable value at ≤ 24.3 psig because ITS uses allowable values calculated in accordance with Engineering Standards Manual IES-3 and IES-3B, Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3) (See ITS 3.3.1, DOC L.1).

f. Confirmation of the applicability of WCAP-10271 to the Indian Point 3 design and operation has already been confirmed by NYPA and reviewed by the NRC as part of Technical Specification Amendment 107, dated March 22, 1991.

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated justification.

A.13 **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) Manual (Phase A). The ITS conversion modifies the CTS requirements as follows:

a. CTS 3.5.1 establishes the Applicability for Engineered Safety Features initiation instrumentation as whenever the plant is not in the cold shutdown condition. ITS requires this function operable in Modes 1, 2, 3 and 4 (i.e., above cold shutdown).

Therefore, there is no change to the existing Applicability.

b. CTS Table 3.5-4 requires 1 operable channel with a minimum degree of redundancy of zero; however, IP3 design includes 2 channels (and 2 pushbuttons) such that either channel (or pushbutton) will initiate both trains of Phase A Isolation. ITS 3.3.2 requires 2 operable channels. This is a more restrictive change (See 3.3.2, DOC M.1).

c. (See ITS 3.3.2, DOC A.4.c)

d. CTS Table 4.1-1 does not establish a specific requirement to test the Containment Phase A Isolation-Manual Initiation Function; however, CTS 4.4, Containment, requires that containment isolation valves be tested in accordance with the Containment Leak Rate Test Program. Consistent with this requirement, ITS SR 3.3.2.6 maintains requirement to verify Operability of the manual initiation function by the performance of a Trip Actuating Device Operational Test (TADOT) every 24 months. The SR is modified by a Note that excludes verification of setpoints during the TADOT for manual initiation Functions because these Functions have no associated setpoints.

e. There is no allowable value or setpoint associated with this function.

f. Confirmation of the applicability of WCAP-10271 to the Indian Point 3 design and operation has already been confirmed by NYPA and reviewed by the NRC as part of Technical Specification Amendment 107, dated March 22, 1991.

Except as noted above, each of the changes described above is an administrative change with no adverse impact on safety.

A.14 **ITS 3.3.2, Function 3.a.(2) Containment Phase A Isolation-Automatic**

Actuation Logic and Actuation Relays, is not listed in the CTS as a required Function but is implicitly required to be Operable to support the Operability of all ESFAS Containment Phase A Isolation Functions (i.e., manual initiation and safety injection). (See ITS 3.3.2, DOC A.4 for the discussion of Automatic Actuation Logic and Actuation Relays.)

A.15 **ITS 3.3.2, Function 3.a.(3) Containment Phase A Isolation-Safety Injection**, is equivalent to CTS Table 3.5-4, Item 1.a. (Containment Isolation) Automatic Safety Injection (Phase A). This Function consists of a contact that initiates Containment Phase A Isolation as result of a Safety Injection Signal. CTS Table 3.5-4, Item 1.a. references CTS Table 3.5-3, Item 1(b), (Safety Injection) High Containment Pressure (Hi Level), for the CTS requirements for this Function. ITS 3.3.2, Function 3.a.(3) Containment Phase A Isolation-Safety Injection, refers to Function 1 (Safety Injection) for all initiation functions and requirements. This cross reference is appropriate because all requirements for inputs to the Containment Phase A 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 3.a.(2) Containment Phase A Isolation-Automatic Actuation Logic and Actuation Relays. Therefore, there are no changes to the existing CTS requirements except as identified and discussed elsewhere (See 3.3.2. DOCs A.5 through A.9 for changes to the Safety Injection Functions that initiate this Function.

A.16 **ITS 3.3.2, Function 3.b.(1) Containment Phase B Isolation-Manual Initiation**, is equivalent to CTS Table 3.5-4, Item 1.c. (Containment Isolation) Manual (Phase B). CTS Table 3.5-4, Item 1.c (Phase B), references Table 3.5-3, Item 2(a) as the source of requirements for this function. This is not correct. CTS Table 3.5-4, Item 1.c (Phase B), has the same design, Operability requirements and testing Requirements as CTS Table 3.5-4, Item 1.c (Phase A). (See ITS 3.3.2, DOC A.13 for a discussion of the changes for this Function.)

A.17 **ITS 3.3.2, Function 3.b.(2) Containment Phase B Isolation-Automatic Actuation Logic and Actuation Relays**, is not listed in the CTS as a required Function but is implicitly required to be Operable to support the Operability of all ESFAS Containment Phase B Isolation Functions (i.e., manual initiation and containment pressure). (See ITS 3.3.2, DOC A.4 for the discussion of Automatic Actuation Logic and Actuation Relays.).

A.18 **ITS 3.3.2, Function 3.b.(3) Containment Phase B Isolation-Containment Pressure (High-High)**, is equivalent to CTS Table 3.5-1, Item 2.a, and CTS Table 3.5-4, Item 1.b. (Containment Isolation) Containment Pressure (Phase B). The ITS conversion modifies the CTS requirements as follows:

a. (See ITS 3.3.2, DOC A.12.a)

b. (See ITS 3.3.2, DOC A.12.b)

c. (See ITS 3.3.2, DOC A.12.b with the exception that the Actions specified in CTS Table 3.5-3, Note 6, are identical to the Actions specified CTS Table 3.5-4, Note 1, for this Function.

d. (See ITS 3.3.2, DOC A.12.d)

e. (See ITS 3.3.2, DOC A.12.e)

f. Confirmation of the applicability of WCAP-10271 to the Indian Point 3 design and operation has already been confirmed by NYPA and reviewed by the NRC as part of Technical Specification Amendment 107, dated March 22, 1991.

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated justification.

A.19 **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.

DISCUSSION OF CHANGES
ITS SECTION 3.3.2 - ENGINEERED SAFETY FEATURE ACTUATION SYSTEM (ESFAS) INSTRUMENTATION

The ITS conversion modifies the CTS requirements as follows:

a. CTS 3.5.1 establishes the Applicability for Engineered Safety Features initiation instrumentation as whenever the plant is not in the cold shutdown condition; however, CTS Table 3.5-4 establishes an implied change to the Applicability by allowing an option of either: cold shutdown (Mode 5); or, shutting all MSIVs if requirements cannot be met. ITS 3.3.2 requires this function operable in Mode 1 and in Modes 2 and 3 unless all MSIVs are closed. This is a less restrictive change because ITS 3.3.2 does not require automatic initiation capability for Containment Isolation in Mode 4 (See 3.3.2, DOC L.4).

b. CTS Table 3.5-4 requires 1 channel per loop with a minimum degree of redundancy of zero. ITS 3.3.2 requires 2 channels per steam line. In the IP3 design, each main steam isolation valve (MSIV) will close if either of two solenoid valves in parallel (channel A and channel B) are opened. The pair of solenoid valves associated with each MSIV are opened by a single switch and there is a separate switch for the pair of solenoid valves associated with each MSIV. Except for the switch in the control room which is common to both channels, there are two separate and redundant circuits (channel A and channel B) capable of closing each MSIV. Requiring 2 channels per steam line to establish redundancy for the manual initiation is a more restrictive change (See 3.3.2, DOC M.1).

c. For a loss of redundancy for the manual trip capability, CTS does not specify any actions because CTS Table 3.5-4 only requires 1 operable channel with a minimum degree of redundancy of zero for the manual initiation function (See 3.3.2, DOC M.1). Under the same conditions, ITS LCO 3.3.2, Action F.1, will require that if one of the two required channels is inoperable (i.e., loss of redundancy but no loss of function) then both channels must be made Operable within 48 hours. This AOT was justified in WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990 (See 3.3.2, DOC

L.3). If requirements are not met within the AOT, both CTS and ITS require only that the plant be placed outside the applicability for Function 4.a, which can be achieved by closing all of the MSIVs even if the plant remains in Mode 2 or 3.

For a loss of function for the manual trip capability, CTS Table 3.5-4, Note 1, requires that the plant be placed in hot shutdown (Mode 3) within the next 4 hours and cold shutdown (Mode 5) within 48 hours. Under the same conditions (loss of manual initiation function), ITS LCO 3.3.2 does not specify a Condition and defaults to LCO 3.0.3. LCO 3.0.3 requires that a plant shutdown be initiated within one hour and the plant be in Mode 3 within 7 hours (versus 4 hours in CTS, See ITS 3.3.2, Doc L.5) and Mode 5 within 37 hours (versus 48 hours in CTS, See ITS 3.3.2, DOC M.5).

d. CTS Table 4.1-1 does not establish a specific requirement to test the Steam Line Isolation-Manual Initiation Function; however, CTS 4.7 establishes requirements for testing the MSIV closing Function every 24 months. ITS SR 3.3.2.6 maintains the same requirement to verify Operability of the manual initiation function by the performance of a Trip Actuating Device Operational Test (TADOT) every 24 months. The SR is modified by a Note that excludes verification of setpoints during the TADOT for manual initiation Functions because these Functions have no associated setpoints.

e. There is no allowable value or setpoint associated with this function.

f. Confirmation of the applicability of WCAP-10271 to the Indian Point 3 design and operation has already been confirmed by NYPA and reviewed by the NRC as part of Technical Specification Amendment 107, dated March 22, 1991 (See 3.3.2, DOC A.36)

Except as noted above, each of the changes described above is an administrative change with no adverse impact on safety.

A.20 **ITS 3.3.2, Function 4.b. Steam Line Isolation-Automatic Actuation Logic and Actuation Relays**, is not listed in the CTS as a required Function but is implicitly required to be Operable to support the Operability of all ESFAS Steam Line Isolation Functions (i.e., manual initiation, containment high pressure, high steam flow in conjunction with Tavg-Low, etc.). (See ITS 3.3.2, DOC A.4 for the discussion of Automatic Actuation Logic and Actuation Relays.)

A.21 **ITS 3.3.2, Function 4.c. Steam Line Isolation-Containment Pressure-High-High**, is equivalent to CTS Table 3.5-1, Item 2.b, and CTS Table 3.5-4, Item 2.b. (Steam Line Isolation) High Containment Pressure (Hi Hi Level). The ITS conversion modifies the CTS requirements as follows:

a. (See 3.3.2, DOC A.12.a and DOC L.4, for changes to the Applicability for this Function.)

b. (See ITS 3.3.2, DOC A.12.b)

c. (See ITS 3.3.2, DOC A.12.b with the exception that the Actions specified in CTS Table 3.5-3, Note 6, are identical to the Actions specified CTS Table 3.5-4, Note 1, for this Function.)
Note that both CTS and ITS require only that the plant be placed outside the applicability for Function 4.c, which can be achieved by closing all of the MSIVs even if the plant remains in Mode 2 or 3.

d. (See ITS 3.3.2, DOC A.12.d)

e. (See ITS 3.3.2, DOC A.12.e)

f. Confirmation of the applicability of WCAP-10271 to the Indian Point 3 design and operation has already been confirmed by NYPA and reviewed by the NRC as part of Technical Specification Amendment 107, dated March 22, 1991.

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated justification.

A.22 **ITS 3.3.2, Function 4.d. Steam Line Isolation-High Steam Flow in Two Steam Lines Coincident with Tavg-Low**, is equivalent to CTS Table 3.5-1, Item 5.b, and CTS Table 3.5-4, Item 2.a.1 (Steam Line Isolation) High Steam Flow in 2/4 Steam Lines Coincident with Low Tavg. The ITS conversion modifies the CTS requirements as follows:

a. (See 3.3.2, DOC A.19.a and DOC L.4, for changes to the Applicability for this Function.)

b. (See 3.3.2, DOC A.8.b for changes to the required number of channels for this Function.)

c. (See 3.3.2, DOC A.8.c for changes to the Required Actions for this Function.)

d. (See 3.3.2, DOC A.8.d, for a discussion of changes to Surveillance Testing for this Function.)

e. (See 3.3.2, DOC A.8.e, for a discussion of changes to the allowable values for this Function.)

f. Confirmation of the applicability of WCAP-10271 to the Indian Point 3 design and operation has already been confirmed by NYPA and reviewed by the NRC as part of Technical Specification Amendment 107, dated March 22, 1991. However, to conform to the assumptions of WCAP-10271, ITS 3.3.2, Function 4.d will increase requirements for steam flow channels to require 2 channels per steam line on all 4 steam lines (versus the CTS requirement for 3 of 4 steam lines) (See 3.2.2, DOC M.2)

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the

associated justification.

A.23 **ITS 3.3.2, Function 4.e. Steam Line Isolation-High Steam Flow in Two Steam Lines Coincident with Steam Line Pressure-Low**, is equivalent to CTS Table 3.5-1, Item 5.b, and CTS Table 3.5-4, Item 2.a.2 (Steam Line Isolation) High Steam Flow in 2/4 Steam Lines Coincident with Low Steam Line Pressure. The ITS conversion modifies the CTS requirements as follows:

a. (See 3.3.2, DOC A.19.a and DOC L.4, for changes to the Applicability for this Function.)

b. (See 3.3.2, DOC A.9.b for changes to the required number of channels for this Function.)

c. (See 3.3.2, DOC A.9.c for changes to the Required Actions for this Function.)

d. (See 3.3.2, DOC A.9.d, for a discussion of changes to Surveillance Testing for this Function.)

e. (See 3.3.2, DOC A.9.e, for a discussion of changes to the allowable values for this Function.)

f. (See 3.3.2, DOC A.22.f, for a discussion of verification of conformance with the assumptions of WCAP-10271.)

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated justification.

A.24 **ITS 3.3.2, Function 5, Feedwater Isolation-Safety Injection**, is equivalent to CTS Table 3.5-4, Item 3.a (Feedwater Line Isolation) Safety Injection Signal. 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. The ITS conversion modifies the CTS requirements as follows:

a. CTS 3.5.1 establishes the Applicability for Engineered Safety Features initiation instrumentation as whenever the plant is not in the cold shutdown and CTS Table 3.5-3 establishes an implied Applicability for this by requiring that the plant be in cold shutdown (Mode 5) if requirements cannot be met.

   ITS requires this function operable in Mode 1 and in Mode 2 except when all Main Boiler Feedpump Discharge Valves (MBFPDVs) or Main Feedwater Regulation Valves (MBFRVs) and MBFRV Low Flow Bypass Valves are closed or isolated by a closed manual valve. This is an administrative change because the safety function is met when all MBFPDVs or MBFRVs and associated bypass valves are closed or isolated by a closed manual valve or the steam driven main boiler feedwater pumps are not operating (i.e., Modes 3 and 4).

b. ITS 3.3.2, Function 5, Feedwater Isolation-Safety Injection, is an output function of each of the ESFAS Safety Injection Functions. CTS Table 3.5-3 implicitly requires 2 operable trains with a minimum degree of redundancy of 1 train (See ITS 3.3.2, DOC A.34) for this function because this configuration is necessary to meet the minimum degree of redundancy requirements for each of the associated ESFAS functions. Therefore, ITS 3.3.2, Function 5, requires that 2 trains are Operable. This combination enforces an unstated requirement that an inoperable train be restored to Operable because with two trains there is no way to re-establish the required redundancy and placing an inoperable train in trip causes an actuation. ITS 3.3.2, Function 5 establishes the requirement for minimum operable channels as "2 trains" and associated Required Action H.1 requires that an inoperable train be restored to Operable. Therefore, there is no change to the existing requirements for minimum number of operable channels or

minimum degree of redundancy.

c. For a loss of redundancy or a loss of function for Automatic Actuation Logic and Actuation Relays, CTS Table 3.5-4, Note 1, requires that an inoperable train must be restored to Operable immediately or the plant be placed in hot shutdown (Mode 3) within the next 4 hours and cold shutdown (Mode 5) within 48 hours of discovery of the inoperable condition. Under the same conditions, ITS 3.3.2 differentiates between one inoperable train (loss of redundancy) and two inoperable trains (loss of function).

For the loss of redundancy (i.e., one train inoperable), ITS 3.3.2, Required Action H.1, allows 6 hours to restore the train to Operable. This AOT was justified in WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990 (See 3.3.2, DOC L.3). If redundancy is not restored within the AOT, ITS 3.3.2, Required Action H.2, requires the plant be in Mode 3 in the following 6 hours (versus 4 hours in CTS, See ITS 3.3.2, Doc L.5). Note that the plant may be placed outside the Applicable Mode by having all MBFPDVs or MBFRVs and associated bypass valves closed or isolated by a closed manual valve.

For a loss of function (i.e., both trains inoperable), ITS LCO 3.3.2 does not specify a Condition and defaults to LCO 3.0.3. LCO 3.0.3 requires that a plant shutdown be initiated within one hour and the plant be in Mode 3 within 7 hours (versus 4 hours in CTS, See ITS 3.3.2, Doc L.5). Note that the plant may be placed outside the Applicable Mode by having all MBFPDVs or MBFRVs and associated bypass valves closed or isolated by a closed manual valve.

d. CTS Table 4.1-1, Item 20.b, requires a test of "ESF Actuation Relay Logic" at the TM Frequency (i.e., every two months on a staggered test basis). ITS SR 3.3.2.2, Actuation Logic Test, maintains the requirement for testing the automatic actuation logic and actuation relays, respectively, at the same Frequency.

Slave relay operation causes equipment to actuate and CTS Table 4.1-1, Item 20.b, is not interpreted as requiring testing of the slave relays. The slave relays are currently tested every 24 months as required by CTS 4.5.A.1.a. ITS SR 3.3.2.5, Slave Relay Test, establishes a requirement to verify operability of the slave relays every 24 months, which is consistent with CTS 4.5.A.1 requirements to test the Safety Injection System.

CTS allowances for bypassing channels and deferring entry into Conditions and Required Actions during testing are maintained (See ITS 3.3.2, DOC A.36).

e. There are no allowable values associated with this function.

f. Confirmation of the applicability of WCAP-10271 to the Indian Point 3 design and operation has already been confirmed by NYPA and reviewed by the NRC as part of Technical Specification Amendment 107, dated March 22, 1991.

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated justification.

A.25 **ITS 3.3.2, Function 6.a, Auxiliary Feedwater-Automatic Actuation Logic and Actuation Relays**, is not listed in the CTS as a required Function but is implicitly required to be Operable to support the Operability of all ESFAS Auxiliary Feedwater initiation Functions (i.e., low low steam generator water level, safety injection loss of all offsite power, etc.). (See ITS 3.3.2, DOC A.4 for the discussion of Automatic Actuation Logic and Actuation Relays.)

A.26 **ITS 3.3.2, Function 6.b Auxiliary Feedwater-SG Water Level-Low Low**, is equivalent to CTS Table 3.5-1, Item 6, and CTS Table 3.5-3, Item 3.a.i. (Auxiliary Feedwater) SG Water Level Low-Low (Start Motor Pumps) and CTS

immediately or the plant be placed in hot shutdown (Mode 3) within the next 4 hours and cold shutdown (Mode 5) within 48 hours of discovery of the inoperable condition.

Under the same conditions, ITS 3.3.2 differentiates between one inoperable channel not in trip (loss of redundancy) and two inoperable channels not in trip (potential loss of function).

For a loss of redundancy for this function, CTS Table 3.5-3, Note 6, requires that an inoperable channel be tripped immediately. Under the same conditions, ITS LCO 3.3.2, Action D.1, allows 6 hours to place the inoperable channel in trip. This AOT was justified in WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990 (See 3.3.2, DOC L.3).

For a loss of redundancy where the required redundancy is not restored by placing the inoperable channel in trip within the AOT, ITS LCO 3.3.2, Required Action D.2.1 and D.2.2, require the plant be in Mode 3 in the following 6 hours (versus 4 hours in CTS, See ITS 3.3.2, Doc L.5) and Mode 4 in 18 hours (See ITS 3.3.2, DOC L.4 for change in the Applicability).

For a potential loss of function (i.e., more than one channel inoperable), ITS LCO 3.3.2 does not specify a Condition and defaults to LCO 3.0.3. LCO 3.0.3 requires that a plant shutdown be initiated within one hour and the plant be in Mode 3 within 7 hours (versus 4 hours in CTS, See ITS 3.3.2, Doc L.5) and Mode 4 within 13 hours (See ITS 3.3.2, DOC L.4 for change in the Applicability).

d. CTS Table 4.1-1, Item 28.a, Steam Generator Level, requires a channel check every shift, a channel test every quarter, and a channel calibration every 24 months. ITS SR 3.3.2.1 requires a channel check every 12 hours which maintains the existing requirement and Frequency; ITS SR 3.3.2.4 requires a channel operational test every 92 days which maintains the existing

Function 1 (Safety Injection) for all initiation functions and requirements. This cross reference is appropriate because all requirements for inputs to the Auxiliary Feedwater-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 6.c. Auxiliary Feedwater-Safety Injection-Automatic Actuation Logic and Actuation Relays. Therefore, there are no changes to the existing CTS requirements except as identified and discussed elsewhere (See 3.3.2, DOCs A.5 through A.9 for changes to the Safety Injection Functions that initiate this Function.)

A.28 **ITS 3.3.2, Function 6.d. Auxiliary Feedwater-Loss of Offsite Power (Non SI Blackout Sequence)**, is equivalent to CTS Table 3.5-3, Item 3.c. (Auxiliary Feedwater) Station Blackout (Start Turbine Pump). The ITS conversion modifies the CTS requirements as follows:

a. CTS 3.5.1 establishes the Applicability for Engineered Safety Features initiation instrumentation as whenever the plant is not in the cold shutdown condition; however, CTS Table 3.5-3 establishes an implied Applicability by requiring that the plant be temperature be reduced to < 350°F (Mode 4) if requirements cannot be met. ITS requires this function operable in Modes 1, 2 and 3 (i.e., Tavg ≥ 350 degrees F). Therefore, there is no change to the existing Applicability requirements.

b. CTS Table 3.5-3 requires 1 operable channel with a minimum degree of redundancy of zero. The IP3 design is that a non-Safety Injection blackout sequence signal from 480 volt bus 3A will start motor driven AFW pump 31 and a non-Safety Injection blackout sequence signal from 480 volt bus 6A will start motor driven AFW pump 33. Additionally, a non-Safety Injection blackout sequence signal from 480 volt bus 3A or 6A will start turbine driven AFW pump 32. Therefore, CTS Table 3.5-3, Item 3.b, requires one channel from either 480 volt bus 3A or 480 volt bus 6A to start the steam driven AFW pump. Additionally, CTS Table 3.5-3, Item

3.b, specifies that this Function is required to start the turbine driven Auxiliary Feed Pump only (i.e., the loss of power prevents the motor driven AFW pump from starting).

ITS Function 6.d is revised to require 1 channel per bus and 2 busses (i.e., one Operable channel for bus 3A and one Operable channel for bus 6A) and the ITS Bases are revised to indicate that this Function is required to start the turbine driven auxiliary driven pump only. Requiring two Operable channels is a more restrictive change (See ITS 3.3.2, DOC M.3).

c. For a loss of redundancy for the Auxiliary Feedwater-Loss of Offsite Power (Non SI Blackout Sequence), 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 the manual initiation function (See 3.3.2, DOC M.3). Under the same conditions, ITS LCO 3.3.2, Action F.2, will require that if one of the two required channels is inoperable (i.e., loss of redundancy but no loss of function) then both channels must be made Operable within 48 hours. This AOT was justified in WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990 (See 3.3.2, DOC L.3).

For a loss of function for Auxiliary Feedwater-Loss of Offsite Power (Non SI Blackout Sequence), CTS Table 3.5-3, Note 6, requires that the plant be placed in hot shutdown (Mode 3) within the next 4 hours and plant be temperature reduced to < 350°F (outside the Applicability) within 48 hours. Under the same conditions (loss of Auxiliary Feedwater-Loss of Offsite Power (Non SI Blackout Sequence function), ITS LCO 3.3.2 does not specify a Condition and defaults to LCO 3.0.3. LCO 3.0.3 requires that a plant shutdown be initiated within one hour and the plant be in Mode 3 within 7 hours (versus 4 hours in CTS, See ITS 3.3.2, Doc L.5) and Mode 4 within 14 hours (versus 48 hours in CTS, See ITS 3.3.2, DOC M.5).

d. CTS Table 4.1-1, Item 28.b, Auxiliary Feedwater-Undervoltage,

requires a channel test every 24 months and a channel calibration every 24 months. ITS SR 3.3.2.6 requires a channel operational test (COT) every 24 months which maintains the existing requirement and Frequency. And, ITS SR 3.3.2.7 requires a channel calibration every 24 months which maintains the existing requirement and Frequency. Therefore, there is no change to the CTS Surveillance requirements for Frequency.

e. CTS Table 3.5-1, Item 7.a, allowable value for the 480 volt Bus Undervoltage Relay Function is ≥ 200 volts. This allowable value was established based on Indian Point Nuclear Generating Station Unit No. 3 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, March 1975, and is considered conservative. ITS 3.3.2, Function 6.d. Auxiliary Feedwater-Loss of Offsite Power, will maintain the CTS value as the allowable value.

f. The IP3 plant design for this Function is not addressed in WCAP-10271 even after requirements were revised to require 1 channel per bus and 2 busses (i.e., one Operable channel for bus 3A and one Operable channel for bus 6A). However, the allowable out of service times and surveillance test intervals are more conservative than CTS requirements (See 3.3.2, DOC M.3), 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 FSAR.

A.29 **ITS 3.3.2, Function 6.e. Auxiliary Feedwater-Trip of Main Boiler Feedwater Pump,** is equivalent to CTS Table 3.5-3, Item 3.d. (Auxiliary Feedwater) Trip of Main Feedwater Pumps (Start Motor Pumps). The ITS conversion modifies the CTS requirements as follows:

a. CTS 3.5.1 establishes the Applicability for Engineered Safety Features initiation instrumentation as whenever the plant is not in the cold shutdown condition; however, CTS Table 3.5-3 establishes an implied Applicability by requiring that the plant

be placed in hot shutdown (Mode 3) if requirements cannot be met. ITS requires this function operable in Modes 1 and 2 when a main feed pump is in operation. This is an administrative change because ITS establishes explicit requirements for Function Applicability that includes all times when the Function is capable of performing its safety Function consistent with the plant design.

b. CTS Table 3.5-3 requires 1 operable channel with a minimum degree of redundancy of zero. The IP3 design is that a single channel associated with each operating MBFP will start both motor driven AFW pumps. 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.4).

c. In conjunction with the revised requirement for 1 channel per operating main feed pump, when MBFP trip channels are inoperable, Required Action I.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 I.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.

d. CTS Table 4.1-1, Item 28.c, Auxiliary Feedwater-Main Feedwater Pump trip, requires a channel test every 24 months. ITS SR 3.3.2.6 requires a channel operational test (COT) every 24 months which maintains the existing requirement and Frequency. Therefore, there is no change to the CTS Surveillance requirements for Frequency.

e. There is no allowable value or setpoint associated with this function.

f. The IP3 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.4), 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 FSAR.

A.30 **ITS 3.3.2, Function 7, ESFAS Interlocks-Pressurizer Pressure**, is equivalent to CTS Table 3.5-3, Item 1.f, Pressurizer Low Pressure (Automatic Unblock), and CTS 3.5.5. The ITS conversion modifies the CTS requirements as follows:

a. (See ITS 3.3.2, DOC A.6.a and DOC L.4 for changes to the Applicability.)

b. (See ITS 3.3.2, DOC A.6.b for changes to the number of required channels.)

c. CTS Table 3.5-3, Note 5, specifies that the Minimum Number of Operable Channels and the Minimum Degree of Redundancy may be reduced to zero if the SI bypass is in the unblocked position. ITS 3.3.2, Required Action K.1, maintains thins requirement by requiring that if one or more channels are inoperable, then verify the interlock is in the required state for existing plant conditions. If this requirement cannot be met, then the shutdown requirements for an inoperable Pressurizer Pressure-Low Function are Applicable (See ITS 3.3.2, DOC A.6.c).

d. (See ITS 3.3.2, DOC A.6.d for changes to surveillance testing requirements.)

e. CTS 3.5.5 specifies that low pressurizer pressure safety injection trip shall be unblocked when the pressurizer pressure is > 2000 psig. ITS 3.3.2, Function 7 establishes the allowable value at

≥ 1998.24 psig because ITS uses allowable values calculated in accordance with Engineering Standards Manual IES-3 and IES-3B, Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3) (See ITS 3.3.1, DOC L.1).

A.31 CTS 3.5.2 specifies that plant operation shall be permitted to continue in accordance with Tables 3.5-2 through 3.5-4 for instrumentation testing or instrumentation channel failure; and, no more than one channel of a particular protection channel set shall be tested at the same time. ITS establishes equivalent requirements and allowances by establishing specific Required Actions for each Function. Specifically, ITS 3.3.1, Required Actions and associated Notes establishing time limits for testing, always require verification that the inoperable channel does not result in a loss of trip Function before allowable out of service time may be applied for testing or inoperability. Additionally, ITS Required Action Notes limit the number of channels made inoperable by testing by requiring that the trip function be maintained during testing (although redundancy may be lost). This is an administrative change with no impact on safety because there is no change to the existing requirements.

A.32 The Actions for ITS 3.3.2, Engineered safety Feature Actuation System (ESFAS) Instrumentation, are preceded by a Note that specifies: "Separate Condition entry is allowed for each Function." This allowance provides explicit recognition that the ITS is designed to allow completely separate re-entry into any Condition for each train and/or channel addressed by the Condition. This includes separate tracking of Completion Times based on this re-entry. This allowance is consistent with an unstated assumption in the CTS. Therefore, the addition of this Note is an administrative change with no impact on safety.

A.33 CTS 3.5.4 includes the allowance "In the case of three loop operation, the out-of-service channel is permitted to be blocked during the test

period." Additionally, CTS Table 3.5-2, Item 8, establish minimum requirements based on the number Operable loops. These allowances are intended to support IP3 operation with fewer than 4 loops Operable and operating. These allowances are not included in the ITS because the current analysis does not support operation with fewer than 4 loops Operable and operating. This is an administrative change with no impact on safety because it eliminates an allowance that cannot be used because of other Technical Specification constraints.

A.34 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.

> Operable channel is defined in CTS 1.7.1 as a channel that will a generate a single protective action signal when required by a plant condition. This definition excludes any channel in the tripped condition. The CTS requirement for minimum operable channels is designed to ensure that sufficient channels are available to adequately monitor the associated plant condition.
>
> Minimum degree of redundancy is defined in CTS 1.8 as the difference between the number of operable channels and the number of channels which when tripped will cause an automatic system trip. The CTS requirement for minimum degree of redundancy is designed to ensure the required ability to tolerate random failures of protective and/or control circuits.

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.

ITS LCOs specify a only the minimum number of Required Channels (which includes all requirements for redundancy) and uses LCO Required Actions to specify that one required channel may be inoperable if placed in trip

or restored to Operable within a specified allowable out of service time (AOT). The Required Actions are specific to each Function and specify the actions that will ensure that both the minimum number of channels and minimum level of redundancy are maintained when one or more channels are inoperable.

In the ITS, requirements for the minimum number of Operable channels are enforced by the combination of a requirement for a minimum number of channels and a specific requirement to restore or trip an inoperable channel. 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.

A.35 CTS Table 3.5-3, Item 2.b. (Containment Spray) High Containment Pressure (Hi Hi Level), references CTS Table 3.5-3, Note 8; and, CTS Table 3.5-4, Item 2.b. (Steam Line Isolation) High Containment Pressure (Hi Hi Level), references CTS Table 3.5-4, Note 2. These Notes specify that only MSIVs need be closed if the only portion of the circuit affected is MSIV closure circuitry. These Notes provide recognition that the same containment high pressure transmitters are used for both MSIV isolation and containment spray. This note is not needed in either CTS or ITS because if containment high pressure transmitters are inoperable, then Required Actions for both the steam line isolation and containment spray are applicable. If the inoperability affects only steam line isolation or containment spray, then only the Required Actions associated with the inoperable function are required. Not including these Notes in ITS is an administrative change with no impact on safety.

A.36 CTS 3.5.4 allows a channel to be blocked for up to 8 hours for testing without taking Actions for an inoperable channel if Function trip capability is maintained. This Note provides two allowances: the ability to bypass an inoperable channel that is in trip to permit performance of required testing; and, the ability to defer entry into Conditions and Required Actions if a channel is inoperable only as a

result of required testing.

ITS 3.3.2, Required Actions C.1, D.1, E.1, G.1 and H.1, maintain the allowance to bypass a channel for 8 hours for testing if function capability is maintained. ITS 3.3.2, Actions Note 2, maintains the allowance to defer entry into Conditions and Required Actions during required testing for up to 8 hours provided the associated Function maintains ESFAS trip capability. ITS LCO 3.3.2, Note 2 to Actions, clarifies this allowance as follows: When a channel or train is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 8 hours provided the associated Function maintains ESFAS trip capability. This testing allowance was justified in WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990. This is an administrative change with no adverse impact on safety because it is a reasonable interpretation of the equivalent CTS requirement.

MORE RESTRICTIVE

M.1 CTS Table 3.5-3 and CTS Table 3.5-4 require only 1 operable channel with a minimum degree of redundancy of zero for ESFAS manual initiation Functions. ITS LCO 3.3.2 increases the requirement for each of these Functions to minimum of 2 Operable channels and establishes Conditions, Required Actions and Completions Times requiring that redundancy be re-established within 48 hours if one of the two required channels is not Operable. This more restrictive change is needed because the Manual ESFAS initiation Functions are designed with redundant capability even though manual Functions are not specifically credited in the accident safety analysis. Redundancy is needed because these Functions are qualitatively credited in the safety analysis and the NRC staff approved licensing basis for the unit. Additionally, manual initiation Functions provide protection for conditions that do not require dynamic transient analysis to demonstrate Function performance. Manual Functions also serve as backups to Functions that were credited in the accident analysis. In conjunction with the requirement for 2 manual trip

channels, ITS LCO 3.3.2, Required Actions, will allow 48 hours to restore an inoperable channel when one of the two channels is inoperable. Allowing 48 hours to restore an inoperable manual initiation is acceptable because the remaining Operable channel is adequate to perform the safety function. Therefore, 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. This change is acceptable because it does not introduce any operation which is un-analyzed while requiring redundant manual ESFAS trip capability. Therefore, this change has no adverse impact on safety.

M.2 For the High Steam Flow Function, the IP3 design consists of 2 channels per steam line of high steam flow and 1 channel per steam line in any 2 steam lines is sufficient for actuation (in combination with a Tavg Low or Steam Pressure Low signal). CTS Table 3.5-3 requires 1 channel per steam line in each of three steam lines and a minimum degree of redundancy of 1 channel per steam line in each of three steam lines. ITS 3.3.2, restates the requirement for minimum operable channels as 2 per steam line (on all four steam lines) Requiring 2 channels per steam line on all 4 steam lines (versus the CTS requirement for 3 of 4 steam lines) is a more restrictive change.

CTS requirements for 2 channels per steam line in only 3 of 4 steam lines is acceptable because this Function provides protection against a steam line break event. This configuration maintains single failure tolerance because a steam line break will cause the steam flow in the remaining intact steam lines to increase to levels above the trip setpoint in order to maintain turbine load. Therefore, even with a single failure of the Function in one steam line and the steam break in a second steam line, steam flow in the remaining two steam lines will increase sufficiently to cause an actuation.

ITS 3.3.2, Function 4.d increases the requirement for minimum operable channels as 2 per steam line on all four steam lines to conform to the

assumptions of WCAP-10271 which justifies extended allowable out of service time and surveillance test intervals. However, requiring this Function to be Operable with a minimum number of channels on all four steam lines justifies the AOT and STI extensions on a 4 loop plant even without the justification in WCAP-10271.

This change is acceptable because it does not introduce any operation which is un-analyzed while requiring greater redundancy in trip capability for this Function. Therefore, this change has no adverse impact on safety.

M.3 CTS Table 3.5-3 requires 1 operable channel with a minimum degree of redundancy of zero for the auxiliary feedwater initiation on undervoltage Function. The IP3 design is that a non-Safety Injection blackout sequence signal from 480 volt bus 3A will start motor driven AFW pump 31 and a non-Safety Injection blackout sequence signal from 480 volt bus 6A will start motor driven AFW pump 33. Additionally, a non-Safety Injection blackout sequence signal from 480 volt bus 3A or 6A will start turbine driven AFW pump 32. Therefore, CTS Table 3.5-3, Item 3.b, requires one channel from either 480 volt bus 3A or 480 volt bus 6A. Additionally, CTS Table 3.5-3, Item 3.b, specifies that this Function is required to start the turbine driven Auxiliary Feed Pump only. ITS Function 6.d is revised to require 1 channel per bus and 2 busses (i.e., one Operable channel for bus 3A and one Operable channel for bus 6A) and the ITS Bases are revised to indicate that this Function is required to start the turbine driven auxiliary driven pump.

This change is needed because requiring two channels of this Function is the minimum configuration that ensures that a single failure of an initiation channel will not result in a loss of Function.

This change is acceptable because it increases the degree of redundancy for a Function assumed to mitigate a loss of feedwater flow event (an abnormal operating occurrence). Additionally, the requirements specified in ITS 3.3.2 are consistent with plant design as described in

the FSAR.

Operating without single failure tolerance during the 48 hour allowable out of service time is acceptable because the Function is a Non-Safety Injection start of the AFW; and, other ESFAS Functions, in particular SG Water Level – Low Low, provide the primary protection against a loss of heat sink (i.e., loss of feedwater) event. This change is acceptable because it does not introduce any operation which is un-analyzed while requiring greater redundancy for a Function assumed to mitigate a loss of feedwater flow event. Therefore, this change has no adverse impact on safety.

M.4 CTS Table 3.5-3 requires 1 operable channel with a minimum degree of redundancy of zero for the auxiliary feedwater pump start on main feedwater pump trip. The IP3 design is that a single channel associated with each operating MBFP will start both motor driven AFW pumps. ITS Function 6.e is revised to require 1 channel per operating main feed pump. In conjunction with this change, ITS LCO 3.3.2, Action I.2,1 will require that if one of the two required channels is inoperable (i.e., loss of redundancy but no loss of function) then both channels must be made Operable within 48 hours. This change is needed because the purpose of this function is to ensure that water is provided to a steam generator to serve as the heat sink. By requiring 1 channel per operating main feed, the IP3 design will provide single failure tolerance for this Function during normal operation (both MBFPs are operating) because single failure tolerance exists only if both MBFPs are operating. Operating without single failure tolerance when only one MBFP is operating and during the 48 hour allowable out of service time is acceptable because the Function is a Non-Safety Injection start of the AFW and other ESFAS Functions, in particular SG Water Level – Low Low, provide the primary protection against a loss of heat sink (i.e., loss of feedwater) event. This change is acceptable because it does not introduce any operation which is un-analyzed while requiring that the trip of any operating MBFP initiate auxiliary feedwater. Therefore, this change has no adverse impact on safety.

M.5 CTS Table 3.5-3, Note 6, and Table 3.5-4, Note 1, establish completion times to complete a reactor shutdown and cooldown or otherwise place the reactor outside the Applicability for any ESFAS Function for which the minimum number of operable channels and/or the minimum degree of redundancy cannot be established. ITS LCO 3.3.2, Required Actions, revise the Completion Times for reactor shutdown and cooldown (or placing the plant outside the Applicable Mode) to be consistent with industry accepted standards for these evolutions as established in NUREG-1431, Standard Technical Specifications, Westinghouse Plants, Rev. 1. These changes are needed because they set Completion Times at the amount of time that permits the shutdown to proceed in a controlled and orderly manner that is well within the specified maximum cooldown rate and within the capabilities of the unit, assuming that only the minimum required equipment is Operable. This reduces thermal stresses on components of the Reactor Coolant System and the potential for a plant upset that could challenge safety systems under conditions that require the shutdown. These changes are acceptable because in lieu of taking Required Actions and meeting Completion Times in ITS 3.3.2, the plant could take the Required Actions prescribed by LCO 3.0.3 and the specified Completion Times are consistent with the Completion Times for reactor shutdown and cooldown if the plant shutdown is required by LCO 3.0.3. This change is acceptable because it does not introduce any operation which is un-analyzed while requiring plant shutdown be completed in within limits consistent with plant capability. Therefore, this change has no adverse impact on safety.

LESS RESTRICTIVE

L.1 CTS trip setpoint limiting safety system setting (allowable value) are based on the IP3 Plant Manual, Volume VI: Precautions, Limitations, and Setpoints, March 1975. ITS will use allowable values calculated in accordance with Engineering Standards Manual IES-3 and IES-3B, Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3). This change is needed because the limiting safety system settings

established by IP3 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 Engineering Standards Manual IES-3 and IES-3B, Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3) 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 CTS 3.5.2 specifies the following: "No more than one channel of a particular protection channel set shall be tested at the same time. By definition, an instrumentation channel failure shall not be regarded as a channel being tested." ITS LCO 3.0.5 establishes an allowance for restoring equipment to service under administrative controls when it has been removed from service or declared inoperable to comply with Actions. The purpose of this Specification is to provide an exception to LCO 3.0.2 (e.g., to not comply with the applicable Required Action(s)) to allow the performance of SRs to demonstrate: (a)The Operability of the equipment being returned to service; or (b) The Operability of other equipment. The ITS Bases for LCO 3.0.5 include the example of this allowance as taking an inoperable channel or trip system out of the tripped condition to prevent the trip function from occurring during the performance of an SR on another channel in the other trip system. A similar example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to permit the logic to function and indicate the appropriate response during the performance of an SR on another channel in the same trip

system. Therefore, ITS LCO 3.0.5 supersedes these restrictions in CTS 3.5.2. This change is acceptable because of the following: (1) ITS 3.3.1, Required Actions and associated Notes establishing time limits for testing, always requires verification that the inoperable channel does not result in a loss of trip Function before allowable out of service time may be applied for testing or inoperability; (2) the duration in test (and therefore, time without single failure tolerance) is limited; and (3) the Westinghouse analog channel fault tree analysis used in WCAP-10271 assumes that more than one channel will be tested at a time. Therefore, this change has no significant impact on safety.

L.3 CTS 3.5.3 and CTS 3.5.4 specify that if requirements for minimum number of channels and/or minimum degree of redundancy cannot be achieved, than the actions specified for that Function, typically plant shutdown, must be initiated immediately (usually interpreted as within one hour). The combination of requirements for minimum number of channels and/or minimum degree of redundancy typically requires that the first inoperable channel for a Function be placed in trip to meet requirements and requires a plant shutdown when a second channel on a single function becomes inoperable. Under the same conditions, ITS 3.3.2, Required Actions, allow 6 hours to restore a channel or place it in trip. The need for and justification for this change is included in WCAP-10271, "Evaluation of Surveillance Frequencies and Out-of-Service Times for the Reactor Protection Instrumentation System" including Supplement 1, and WCAP-10271, Supplement 2, "Evaluation of Surveillance Frequencies and Out of Service Times for the Engineered Safety Features Actuation Systems." This justification was approved by the NRC in Safety Evaluations dated February 1985 and February 1989. Confirmation of the applicability of WCAP-10271 to the Indian Point 3 design and operation has already been confirmed by the NYPA and reviewed by the NRC as part of Technical Specification Amendment 107, dated March 22, 1991. Therefore, this change has no significant adverse impact on safety.

L.4 CTS 3.5.1 requires that ESFAS initiation instrumentation must be

Operable in when the plant is not in the cold shutdown condition (i.e., Modes 1, 2, 3 and 4). ITS 3.3.2 revises the Applicability for all ESFAS Functions such that automatic initiation capability is not required in Mode 4 or if the ESFAS Safety function is satisfied (e.g., MSIVs are already closed). Manual initiation capability will still be required in Mode 4 and automatic actuation logic and actuation relays will be required in Mode 4 only as necessary to support manual initiation capability and ITS LCO 3.3.6, Containment Purge System and Pressure Relief Line Isolation Instrumentation, and LCO 3.3.7, Control Room Emergency Ventilation (CRVS) Actuation Instrumentation. Eliminating requirements for automatic ESFAS initiation instrumentation in Mode 4 is acceptable because when in Mode 4 there is insufficient energy in the primary or secondary systems to warrant automatic initiation of ESF systems in response to abnormal or accident conditions. Therefore, in Mode 4, adequate time is available for an operator to evaluate unit conditions and respond by manually starting individual systems, pumps, and other equipment to mitigate the consequences of an abnormal condition or accident. Restrictions on manual initiation in Mode 4 are already recognized in Technical Specifications related to Low Temperature Overpressure Protection which requires that safety injection systems are administratively locked out or otherwise prevented from actuating to prevent inadvertent overpressurization of unit systems. Therefore, this change has no adverse impact on safety.

L.5 For the loss of ESFAS redundancy, ITS LCO 3.3.2 Required Actions specify that the plant be in Mode 3 in the following 6 hours (versus 4 hours in CTS Table 3.5-3, Note 6 and Table 3.5-4, Note 1). For the loss of ESFAS function, ITS LCO 3.0.3 specifies that a plant shutdown be initiated within one hour and the plant be in Mode 3 within 7 hours (versus 4 hours in CTS Table 3.5-3, Note 6 and Table 3.5-4, Note 1).

ITS LCO 3.3.2, Required Actions, revise the Completion Times for reactor shutdown and cooldown (or placing the plant outside the Applicable Mode) to be consistent with industry accepted standards for these evolutions as established in NUREG-1431, Standard Technical Specifications,

Westinghouse Plants, Rev. 1. These changes are needed because they set Completion Times at the amount of time that permits the shutdown to proceed in a controlled and orderly manner that is well within the specified maximum cooldown rate and within the capabilities of the unit, assuming that only the minimum required equipment is Operable. This reduces thermal stresses on components of the Reactor Coolant System and the potential for a plant upset that could challenge safety systems under conditions that require the shutdown. These changes are acceptable because in lieu of taking Required Actions and meeting Completion Times in ITS 3.3.2, the plant could take the Required Actions prescribed by LCO 3.0.3 and the specified Completion Times are consistent with the Completion Times for reactor shutdown and cooldown if the plant shutdown is required by LCO 3.0.3. This change is acceptable because it does not introduce any operation which is un-analyzed while requiring plant shutdown be completed in within limits consistent with plant capability. Therefore, this change has no adverse impact on safety.

REMOVED DETAIL

LA.1 CTS Section 3.5, Tables 3.5-2, 3.5-3 and 3.5-4, Columns 1 and 2, identify the number of channels and the channels required to trip for each RPS and ESFAS Function. ITS LCO 3.3.1, LCO 3.3.2, LCO 3.3.3, LCO 3.3.5 and LCO 3.3.6 require that these Functions be Operable but do not provide system design details. This is acceptable because this design information is incorporated into the minimum requirements and ITS specifies the minimum requirements for Operability.

This change is acceptable because ITS LCO 3.3.1, LCO 3.3.2, LCO 3.3.3, LCO 3.3.5 and LCO 3.3.6 maintain the existing requirements for the Operability of these instruments (except as identified and justified in this discussion of change); therefore, there is no change to the existing requirements and no change to the level of safety of facility operation.

This change, which allows the description of the design of instrument

functions to be maintained in the FSAR and the detailed description of the requirements for Operability of these functions to be maintained in the ITS Bases, is consistent with the approach used in NUREG-1431 for all Limiting Conditions for Operation (LCOs). This approach is acceptable because the requirements of 10 CFR 50.59, Changes, Tests and Experiments, and ITS 5.5.13, Technical Specifications (TS) Bases Control Program, are designed to assure that changes to the FSAR and ITS Bases do not result in changes to the Technical Specification requirements and do not result in significant increases in the probability or consequences of accidents previously evaluated, do not create the possibility of a new or different kind of accident, and do not result in a significant reduction in a margin of safety. Additionally, IP3 programs that implement FSAR changes in accordance with 10 CFR 50.59 and ITS Bases changes in accordance with ITS 5.5.13 require periodic submittal of FSAR and Bases changes to the NRC for review.

This change is a less restrictive administrative change with no impact on safety because no requirements are being deleted from Technical Specifications and an appropriate change control process and an appropriate level of regulatory oversight are maintained for the information being relocated out of the Technical Specifications.

LA.2 CTS Tables 3.5-2, 3.5-3 and 3.5-4 and 4.1-1 include remarks and clarification notes that are not directly related to the Operability of any RPS or ESFAS Function. 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 5.5.12, 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 NYPA 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.

Indian Point 3
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Technical Specification 3.3.2:

"Engineered Safety Feature Actuation System (ESFAS) Instrumentation"

PART 4:

No Significant Hazards Considerations for Changes between CTS and ITS that are Less Restrictive

No Significant Hazard Considerations for Changes that are Administrative, More Restrictive, and Removed Details are the same for all Packages. A Copy is included at the end of the Package.

NO SIGNIFICANT HAZARDS EVALUATION
ITS SECTION 3.3.2 - ENGINEERED SAFETY FEATURE ACTUATION SYSTEM (ESFAS) INSTRUMENTATION

LESS RESTRICTIVE
("L.1" Labeled Comments/Discussions)

New York Power Authority has evaluated the proposed Technical Specification change identified as "Less Restrictive" in accordance with the criteria set forth in 10 CFR 50.92, and has determined that the proposed change does not involve a significant hazards consideration. The bases for the determination that the proposed change does not involve a significant hazards consideration are discussed below.

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

   CTS trip setpoint limiting safety system setting (allowable value) are based on the IP3 Plant Manual, Volume VI: Precautions, Limitations, and Setpoints, March 1975. ITS will use allowable values calculated in accordance with Engineering Standards Manual IES-3 and IES-3B, Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3). This change is needed because the limiting safety system settings established by IP3 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 will not result in a significant increase in the probability of an accident previously evaluated because a small change in the allowable value for an RPS or ESFAS actuation instrumentation is not assumed as the initiator of any accident previously evaluated. This change will not result in a significant increase in the consequences of an accident previously evaluated because the allowable values calculated in accordance with Engineering Standards Manual IES-3 and IES-3B, Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3). This methodology ensures 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 provides 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.

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

   The proposed change will not involve any physical changes to systems, structures, or components, or involve a change in normal plant operation. Therefore, it will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   This change does not involve a significant reduction in a margin of safety because the existing limiting safety system setting and the proposed allowable values use the information and methods available at the time to determine instrument settings that ensure that safety limits are not exceeded during any event.

LESS RESTRICTIVE
("L.2" Labeled Comments/Discussions)

New York Power Authority has evaluated the proposed Technical Specification change identified as "Less Restrictive" in accordance with the criteria set forth in 10 CFR 50.92, and has determined that the proposed change does not involve a significant hazards consideration. The bases for the determination that the proposed change does not involve a significant hazards consideration are discussed below.

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

   This change eliminates a restriction in current Technical Specifications that could preclude implementation of ITS LCO 3.0.5 which establishes an allowance for restoring equipment to service under administrative controls when it has been removed from service or declared inoperable to

comply with Actions. This change will permit taking an inoperable channel or trip system out of the tripped condition to prevent the trip function from occurring during the performance of an SR on another channel in the other trip system. This change will not result in a significant increase in the probability of an accident previously evaluated because the status of an RPS or ESFAS instrument channel is not assumed as the initiator of any accident previously evaluated. This change will not result in a significant increase in the consequences of an accident previously evaluated because of the following: (1) ITS 3.3.1 and 3.3.2, Required Actions (as modified by TSTF-135 (WOG-58), RPS and ESFAS Instrumentation) and associated Notes establishing time limits for testing, always require verification that the inoperable channel does not result in a loss of trip Function before allowable out of service time may be applied for testing or inoperability; and, (2) the duration in test is limited and, therefore, the time the channel cannot tolerate a single failure is limited.

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

   The proposed change will not involve any physical changes to systems, structures, or components, or involve a change in normal plant operation. Therefore, it will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   This change does not involve a significant reduction in a margin of safety because the Westinghouse analog channel fault tree analysis used in WCAP-10271 assumes that more than one channel will be tested at a time. Safety Evaluations for WCAP-10271 concluded that all of the changes justified in WCAP-10271 determined that an overall conservative upper bound for the core damage frequency (CDF) increase due to the proposed STI/AOT changes is slightly less than 6 percent for Westinghouse PWR plants. The staff also concluded that actual CDF increases for individual plants are expected to be substantially less than 6 percent. This CDF increase to be small compared to the range of uncertainty in the CDF analyses and therefore acceptable. Based on the

WCAP-10271 analyses and subsequent NRC review, the NRC concluded that the proposed STI and AOT changes for the ESFAS and RTS would have only a small and, therefore, acceptable impact on overall plant risk.

LESS RESTRICTIVE
("L.3" Labeled Comments/Discussions)

New York Power Authority has evaluated the proposed Technical Specification change identified as "Less Restrictive" in accordance with the criteria set forth in 10 CFR 50.92, and has determined that the proposed change does not involve a significant hazards consideration. The bases for the determination that the proposed change does not involve a significant hazards consideration are discussed below.

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

   This change extends the allowable out of service time to restore or trip an inoperable channel from 1 hour to 6 hours if the inoperable channel does not result in a loss of the Function's trip capability. This change will not result in a significant increase in the probability of an accident previously evaluated because the status of an RPS or ESFAS instrument channel is not assumed as the initiator of any accident previously evaluated. This change will not result in a significant increase in the consequences of an accident previously evaluated because ITS 3.3.2 (as modified by TSTF-135 (WOG-58)), Required Actions, always require verification that the inoperable channel does not result in a loss of trip Function before the 6 hour allowable out of service time may be applied. Therefore, the Function is always Operable and the time that the Function cannot tolerate a single failure is limited based on the analysis in WCAP-10271, "Evaluation of Surveillance Frequencies and Out-of-Service Times for the Reactor Protection Instrumentation System" including Supplement 1, and WCAP-10271, Supplement 2, "Evaluation of Surveillance Frequencies and Out of Service Times for the Engineered Safety Features Actuation Systems."

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

   The proposed change will not involve any physical changes to systems, structures, or components, or involve a change in normal plant operation. Therefore, it will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   This change does not involve a significant reduction in a margin of safety because ITS 3.3.2 (as modified by TSTF-135 (WOG-58)), Required Actions, always require verification that the inoperable channel does not result in a loss of trip Function before the 6 hour allowable out of service time may be applied. Therefore, the Function is always Operable and the time that the Function cannot tolerate a single failure is limited based on the analysis in WCAP-10271, "Evaluation of Surveillance Frequencies and Out-of-Service Times for the Reactor Protection Instrumentation System" including Supplement 1, and WCAP-10271, Supplement 2, "Evaluation of Surveillance Frequencies and Out of Service Times for the Engineered Safety Features Actuation Systems." Safety Evaluations for WCAP-10271 concluded that all of the changes justified in WCAP-10271 determined that an overall conservative upper bound for the core damage frequency (CDF) increase due to the proposed STI/AOT changes is slightly less than 6 percent for Westinghouse PWR plants. The staff also concluded that actual CDF increases for individual plants are expected to be substantially less than 6 percent. This CDF increase to be small compared to the range of uncertainty in the CDF analyses and therefore acceptable. Based on the WCAP-10271 analyses and subsequent NRC review, the NRC concluded that the proposed STI and AOT changes for the ESFAS and RTS would have only a small and, therefore, acceptable impact on overall plant risk.

NO SIGNIFICANT HAZARDS EVALUATION
ITS SECTION 3.3.2 - ENGINEERED SAFETY FEATURE ACTUATION SYSTEM (ESFAS) INSTRUMENTATION

LESS RESTRICTIVE
("L.4" Labeled Comments/Discussions)

New York Power Authority has evaluated the proposed Technical Specification change identified as "Less Restrictive" in accordance with the criteria set forth in 10 CFR 50.92, and has determined that the proposed change does not involve a significant hazards consideration. The bases for the determination that the proposed change does not involve a significant hazards consideration are discussed below.

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

   This change eliminates requirements for automatic initiation capability for Safety Injection in Mode 4. CTS 3.5.1 requires that ESFAS initiation instrumentation must be Operable in when the plant is not in the cold shutdown condition (i.e., Modes 1, 2, 3 and 4). ITS 3.3.2 revises the Applicability for all ESFAS Functions such that automatic initiation capability is not required in Mode 4 or if the ESFAS Safety function is satisfied (e.g., MSIVs are already closed). Manual initiation capability will still be required in Mode 4 and automatic actuation logic and actuation relays will be required in Mode 4 only as necessary to support manual initiation capability and ITS LCO 3.3.6, Containment Purge System and Pressure Relief Line Isolation Instrumentation, and LCO 3.3.7, Control Room Emergency Ventilation (CRVS) Actuation Instrumentation.

   This change will not result in a significant increase in the probability of an accident previously evaluated because ESFAS initiation status is not the initiator of any analyzed event. This change will not result in a significant increase in the consequences of an accident previously evaluated because when in Mode 4 there is insufficient energy in the primary or secondary systems to warrant automatic initiation of ESF systems in response to abnormal or accident conditions. Therefore, in Mode 4, adequate time is available for an operator to evaluate unit conditions and respond by manually starting individual systems, pumps, and other equipment to mitigate the consequences of an abnormal

condition or accident. Requirements for manual initiation in Mode 4 is already recognized in Technical Specifications related to Low Temperature Overpressure Protection which requires that safety injection systems are administratively locked out or otherwise prevented from actuating to prevent inadvertent overpressurization of unit systems.

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

   The proposed change will not involve any physical changes to systems, structures, or components, or involve a change in normal plant operation. Therefore, it will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   This change does not involve a significant reduction in a margin of safety because when in Mode 4 there is insufficient energy in the primary or secondary systems to warrant automatic initiation of ESF systems in response to abnormal or accident conditions. Therefore, in Mode 4, adequate time is available for an operator to evaluate unit conditions and respond by manually starting individual systems, pumps, and other equipment to mitigate the consequences of an abnormal condition or accident. Requirements for manual initiation in Mode 4 is already recognized in Technical Specifications related to Low Temperature Overpressure Protection which requires that safety injection systems are administratively locked out or otherwise prevented from actuating to prevent inadvertent overpressurization of unit systems.

LESS RESTRICTIVE
("L.5" Labeled Comments/Discussions)

New York Power Authority has evaluated the proposed Technical Specification change identified as "Less Restrictive" in accordance with the criteria set forth in 10 CFR 50.92, and has determined that the proposed change does not involve a significant hazards consideration. The bases for the determination that the proposed change does not involve a significant hazards consideration

are discussed below.

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

   ITS LCO 3.3.2, Required Actions, revise the Completion Times for reactor shutdown and cooldown (or placing the plant outside the Applicable Mode) to be consistent with industry accepted standards for these evolutions as established in NUREG-1431, Standard Technical Specifications, Westinghouse Plants, Rev. 1. For the loss of ESFAS redundancy, ITS LCO 3.3.2 Required Actions specify that the plant be in Mode 3 in the following 6 hours (versus 4 hours in CTS Table 3.5-3, Note 6 and Table 3.5-4, Note 1). For the loss of ESFAS function, ITS LCO 3.0.3 specifies that a plant shutdown be initiated within one hour and the plant be in Mode 3 within 7 hours (versus 4 hours in CTS Table 3.5-3, Note 6 and Table 3.5-4, Note 1).

   This change will not result in a significant increase in the probability of an accident previously evaluated because allowing several additional hours to perform a plant shutdown ha no affect on the initiator of any analyzed event. This change will not result in a significant increase in the consequences of an accident previously evaluated because they set Completion Times at the amount of time that permits the shutdown to proceed in a controlled and orderly manner that is well within the specified maximum cooldown rate and within the capabilities of the unit, assuming that only the minimum required equipment is Operable. This reduces thermal stresses on components of the Reactor Coolant System and the potential for a plant upset that could challenge safety systems under conditions that require the shutdown. These changes are acceptable because in lieu of taking Required Actions and meeting Completion Times in ITS 3.3.2, the plant could take the Required Actions prescribed by LCO 3.0.3 and the specified Completion Times are consistent with the Completion Times for reactor shutdown and cooldown if the plant shutdown is required by LCO 3.0.3. This change is acceptable because it does not introduce any operation which is un-analyzed while requiring plant shutdown be completed in within limits consistent with plant capability.

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

   The proposed change will not involve any physical changes to systems, structures, or components, or involve a change in normal plant operation. Therefore, it will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   This change does not involve a significant reduction in a margin of safety because they set Completion Times at the amount of time that permits the shutdown to proceed in a controlled and orderly manner that is well within the specified maximum cooldown rate and within the capabilities of the unit, assuming that only the minimum required equipment is Operable. This reduces thermal stresses on components of the Reactor Coolant System and the potential for a plant upset that could challenge safety systems under conditions that require the shutdown. These changes are acceptable because in lieu of taking Required Actions and meeting Completion Times in ITS 3.3.2, the plant could take the Required Actions prescribed by LCO 3.0.3 and the specified Completion Times are consistent with the Completion Times for reactor shutdown and cooldown if the plant shutdown is required by LCO 3.0.3. This change is acceptable because it does not introduce any operation which is un-analyzed while requiring plant shutdown be completed in within limits consistent with plant capability.

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PART 5:

NUREG-1431
Annotated to show differences between NUREG-1431 and ITS

Status of NUREG 1431 Generic Changes for ITS 3.3.2

This ITS Specification is based on NUREG-1431 Specification No. **3.3.2**
as modified by the following Generic Changes:

OG No.	TSTF No.	Generic Change Description	NRC STATUS	IP3 STATUS	JD No.
WOG-052 R1	**111 R1**	REVISE BASES FOR SR 3.3.1.16 AND 3.3.2.10 TO ELIMINATE PRESSURE SENSOR RESPONSE TIME TESTING	NRC Review	IP3 has no requirement for response time testing.	**N/A**
WOG-058	**135 R0**	RPS AND ESFAS INSTRUMENTATION	Rejected by NRC	Not Incorporated	**N/A**
WOG-058 R1	**135 R1**	RPS AND ESFAS INSTRUMENTATION	Rejected by NRC	Not Incorporated	**N/A**
WOG-058 R2	**135 R2**	RPS AND ESFAS INSTRUMENTATION	NRC Review	Incorporated.	**T.1**

3.3 INSTRUMENTATION

(CTS) 3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

(3.5) LCO 3.3.2 The ESFAS instrumentation for each Function in Table 3.3.2-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.2-1.

ACTIONS (1.) Insert 3.3-23-01

(DOC A.32) NOTE (5)
Separate Condition entry is allowed for each Function.

	CONDITION	REQUIRED ACTION	COMPLETION TIME
(3.5.3)	A. One or more Functions with one or more required channels or trains inoperable.	A.1 Enter the Condition referenced in Table 3.3.2-1 for the channel(s) or train(s).	Immediately
(DOC A.3) (DOC A.10) (DOC A.13) (DOC A.16)	B. One channel or train inoperable.	B.1 Restore channel or train to OPERABLE status.	48 hours
		OR	
		B.2.1 Be in MODE 3.	54 hours
		AND	
		B.2.2 Be in MODE 5.	84 hours

(continued)

NUREG-1431 Markup Inserts
ITS SECTION 3.3.2 - ENGINEERED SAFETY FEATURE ACTUATION SYSTEM (ESFAS) INSTRUMENTATION

INSERT: 3.3-23-01

(CLB:1)

<DOC A. 36>

2. When a channel or train is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 8 hours provided the associated Function maintains ESFAS trip capability.

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One train inoperable.	C.1 --------NOTE--------- One train may be bypassed for up to 8 [4] hours for surveillance testing provided the other train is OPERABLE. ----------	
	Restore train to OPERABLE status.	6 hours
	OR	
	C.2.1 Be in MODE 3.	12 hours
	AND	
	C.2.2 Be in MODE 5.	42 hours
D. One channel inoperable.	D.1 --------NOTE--------- The inoperable channel may be bypassed for up to 8 [4] hours for surveillance testing of other channels. ----------	
	Place channel in trip.	6 hours
	OR	
	D.2.1 Be in MODE 3.	12 hours
	AND	
	D.2.2 Be in MODE 4.	18 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. One Containment Pressure channel inoperable. (one or both sets of three)	E.1 ---------NOTE--------- One additional channel may be bypassed for up to [4] (8) hours for surveillance testing. ---------- Place channel in bypass. (trip)	6 hours
	OR	
	E.2.1 Be in MODE 3.	12 hours
	AND	
	E.2.2 Be in MODE 4.	18 hours
F. One channel or train inoperable.	F.1 Restore channel or train to OPERABLE status.	48 hours
	OR	
	F.2.1 Be in MODE 3.	54 hours
	AND	
	F.2.2 Be in MODE 4.	60 hours

(DOC A.12)
(DOC A.18)

(DOC A.19)
(DOC A.28)

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
G. One train inoperable.	G.1 --------NOTE--------- One train may be bypassed for up to (8) [4] hours for surveillance testing provided the other train is OPERABLE. ----------	
	Restore train to OPERABLE status.	6 hours
	OR	
	G.2.1 Be in MODE 3.	12 hours
	AND	
	G.2.2 Be in MODE 4.	18 hours
H. One train inoperable.	H.1 --------NOTE--------- One train may be bypassed for up to (8) [4] hours for surveillance testing provided the other train is OPERABLE. ----------	
	Restore train to OPERABLE status.	6 hours
	OR	
	H.2 Be in MODE 3.	12 hours

<DOC A.20>
<DOC A.25>
<DOC A.24>

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
I. One channel inoperable.	I.1 --------NOTE--------- The inoperable channel may be bypassed for up to [4] hours for surveillance testing of other channels. ---------- Place channel in trip.	6 hours
	OR	
	I.2 Be in MODE 3.	12 hours
(T) J. ~~One~~ Main Feedwater Pumps (S) trip channel inoperable. <DOC A-29> Insert: 3.3-27-01	J.1 Restore channel to OPERABLE status.	48 hours
	OR	
	J.2 Be in MODE 3.	54 hours
K. One channel inoperable.	K.1 --------NOTE--------- One additional channel may be bypassed for up to [4] hours for surveillance testing. ---------- Place channel in bypass.	6 hours
	OR	

(continued)

NUREG-1431 Markup Inserts
ITS SECTION 3.3.2 - ENGINEERED SAFETY FEATURE ACTUATION SYSTEM (ESFAS) INSTRUMENTATION

Insert: 3.3-27-01

<DOC A.29>	I.1.X	Verify one channel associated with an operating MBFP is OPERABLE.	Immediately
	AND		
<DOC M.4>	I.2X	Restore one channel associated with each operating MBFP to OPERABLE status.	48 hours
J. Required Action and associated Completion Time of Condition I not met.	J.1	Be in MODE 3.	6 hours

ACTIONS

<CTS>

CONDITION	REQUIRED ACTION	COMPLETION TIME
K. (continued)	K.2.1 Be in MODE 3. AND K.2.2 Be in MODE 5.	12 hours 42 hours
<DOC A.30> <3.5.5> K. One channel or more channels inoperable.	K.1 Verify interlock is in required state for existing unit condition. OR K.2.1 Be in MODE 3. AND K.2.2 Be in MODE 4.	1 hour 7 hours 13 hours

T.1

SURVEILLANCE REQUIREMENTS

----------NOTE----------
Refer to Table 3.3.2-1 to determine which SRs apply for each ESFAS Function.

SURVEILLANCE		FREQUENCY
SR 3.3.2.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.2.2	Perform ACTUATION LOGIC TEST.	31 days on a STAGGERED TEST BASIS
SR 3.3.2.3	----------NOTE---------- The continuity check may be excluded. ---------- Perform ACTUATION LOGIC TEST.	31 days on a STAGGERED TEST BASIS
SR 3.3.2.~~4~~ 3	Perform MASTER RELAY TEST.	31 days on a STAGGERED TEST BASIS
SR 3.3.2.~~5~~ 4	Perform COT.	92 days
SR 3.3.2.~~6~~ 5	Perform SLAVE RELAY TEST.	~~[92] days~~ 24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.2.7	~~----------NOTE----------~~ ~~Verification of relay setpoints not required.~~ ~~----------~~ ~~Perform TADOT.~~	~~[92] days~~
<DOC A.3> SR 3.3.2.~~8~~ 6	----------NOTE---------- Verification of setpoint not required for manual initiation functions. ---------- Perform TADOT.	~~[18]~~ 24 months
SR 3.3.2.~~9~~ 7	----------NOTE---------- This Surveillance shall include verification that the time constants are adjusted to the prescribed values. ---------- Perform CHANNEL CALIBRATION.	~~[18]~~ 24 months
~~SR 3.3.2.10~~	~~----------NOTE----------~~ ~~Not required to be performed for the turbine driven AFW pump until [24] hours after SG pressure is ≥ [1000] psig.~~ ~~----------~~ ~~Verify ESFAS RESPONSE TIMES are within limit.~~	~~[18] months on a STAGGERED TEST BASIS~~

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE	FREQUENCY
SR 3.3.2.11 ----------NOTE---------- Verification of setpoint not required. ---------- Perform TADOT.	Once per reactor trip breaker cycle

Table 3.3.2-1 (page 1 of 8)
Engineered Safety Feature Actuation System Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	TRIP SETPOINT[a]
	1. Safety Injection						
<DOC A.3>	a. Manual Initiation	1,2,3,4	2	B	SR 3.3.2.~~8~~ (6)	NA	NA
<DOC A.4>	b. Automatic Actuation Logic and Actuation Relays	1,2,3,4 (a)	2 trains	C	SR 3.3.2.2 (3) SR 3.3.2.4 (5) SR 3.3.2.6	NA	NA
<DOC A.5>	c. Containment Pressure – High (X)	1,2,3	3	D	SR 3.3.2.1 (4) SR 3.3.2.5 (7) SR 3.3.2.9 ~~SR 3.3.2.10~~	≤ ~~[3.86]~~ 4.80 psig	≤ [3.6] psig
<DOC A.6>	d. Pressurizer Pressure – Low	1,2,3[b]	~~[3]~~	D	SR 3.3.2.1 (4) SR 3.3.2.5 (7) SR 3.3.2.9 ~~SR 3.3.2.10~~	≥ ~~[1850]~~ 1684.64 psig	≥ [1850] psig
	(e) ~~Steam Line Pressure~~						
	~~(1) Low~~	~~1,2,3[(b)]~~	~~3 per steam line~~	~~D~~	~~SR 3.3.2.1~~ ~~SR 3.3.2.5~~ ~~SR 3.3.2.9~~ ~~SR 3.3.2.10~~	~~≥ [635] psig~~	~~≥ [675] psig~~
<DOC A.7>	(2) High Differential Pressure Between Steam Lines	1,2,3	3 per steam line (h)	D	SR 3.3.2.1 SR 3.3.2.5 (4) SR 3.3.2.9 (7) ~~SR 3.3.2.10~~	≤ ~~[186]~~ 208 psig	≤ [97] psig
<DOC A.8>	f. High Steam Flow in Two Steam Lines	1,2,3[(c)] (d)	2 per steam line	D	SR 3.3.2.1 (4) SR 3.3.2.5 (7) SR 3.3.2.9 ~~SR 3.3.2.10~~	~~(e)~~ (c)	(f)
	Coincident with T_{avg} – Low (Low)	1,2,3[(d)]	1 per loop (i)	D	SR 3.3.2.1 (4) SR 3.3.2.5 SR 3.3.2.9 (7) ~~SR 3.3.2.10~~	≥ ~~[550.6]~~ 535.6 °F	≥ [553] °F

(continued)

(a) Reviewer's Note: Unit specific implementations may contain only Allowable Value depending on Setpoint Study methodology used by the unit.
(b) Above the P-11 (Pressurizer Pressure) interlock.
(c) Time constants used in the lead/lag controller are $t_1 \geq$ [50] seconds and $t_2 \leq$ [5] seconds.
(d) Above the P-12 (T_{avg} – Low Low) interlock.
(e) Less than or equal to a function defined as ΔP corresponding to [44]% full steam flow below [20]% load, and ΔP increasing linearly from [44]% full steam flow at [20]% load to [114]% full steam flow at [100]% load, and ΔP corresponding to [114]% full steam flow above 100% load.
(f) Less than or equal to a function defined as ΔP corresponding to [40]% full steam flow between [0]% and [20]% load and then a ΔP increasing linearly from [40]% steam flow at [20]% load to [110]% full steam flow at [100]% load.

Insert: 3.3-32-01

NUREG-1431 Markup Inserts
ITS SECTION 3.3.2 - ENGINEERED SAFETY FEATURE ACTUATION SYSTEM (ESFAS) INSTRUMENTATION

Insert: 3.3-32-01

(a) Only as needed to support Manual initiation capability when in MODE 4.

(b) Above the Pressurizer Pressure interlock.

<3.5.5> (c) Less than or equal to turbine first stage pressure corresponding to 54.4% full steam flow below 20% load, and increasing linearly from 54.4% full steam flow at 20% load to 110% full steam flow at 100% load, and corresponding to 110% full steam flow above 100% load. Time delay for SI ≤ 6 seconds.

(d) Except when all MSIVs are closed.

(h) Separate Condition entry is allowed for each steam line.

(i) Separate Condition entry is allowed for each loop.

Table 3.3.2-1 (page 2 of 8)
Engineered Safety Feature Actuation System Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	TRIP SETPOINT[a]
	1. Safety Injection (continued)						
<DOC A.9>	g. High Steam Flow in Two Steam Lines	1,2,3[d]	2 per steam line	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 ~~SR 3.3.2.10~~	[e]	[f]
	Coincident with Steam Line Pressure – Low	1,2,3[d]	1 per steam line	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 ~~SR 3.3.2.10~~	≥ [635] psig	≥ [675] psig
	2. Containment Spray						
<DOC A.10>	a. Manual Initiation	1,2,3,4	2 per train, 2 trains	B	SR 3.3.2.8	NA	NA
<DOC A.11>	b. Automatic Actuation Logic and Actuation Relays	1,2,3,4	2 trains	C	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.6	NA	NA
<DOC A.12>	c. Containment Pressure ~~High – 3~~ (High High)	1,2,3	4 (2 sets of 3)	E	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 ~~SR 3.3.2.10~~	≤ [12.31] psig	≤ [12.05] psig
	~~High – 3 (Two Loop Plants)~~	~~1,2,3~~	~~[3] sets of [2]~~	~~E~~	~~SR 3.3.2.1~~ ~~SR 3.3.2.5~~ ~~SR 3.3.2.9~~ ~~SR 3.3.2.10~~	~~≤ [12.31] psig~~	~~≤ [12.05] psig~~

(continued)

(a) ~~Reviewer's Note: Unit specific implementations may contain only Allowable Value depending on Setpoint Study methodology used by the unit.~~
(c) ~~Time constants used in the lead/lag controller are $t_1 \geq$ [50] seconds and $t_2 \leq$ [5] seconds.~~
(d) ~~Above the P-12 (T_{avg} – Low Low) interlock.~~
(e) ~~Less than or equal to a function defined as ΔP corresponding to [44]% full steam flow below [20]% load, and ΔP increasing linearly from [44]% full steam flow at [20]% load to [114]% full steam flow at [100]% load, and ΔP corresponding to [114]% full steam flow above 100% load.~~
(f) ~~Less than or equal to a function defined as ΔP corresponding to [40]% full steam flow between [0]% and [20]% load and then a ΔP increasing linearly from [40]% steam flow at [20]% load to [110]% full steam flow at [100]% load.~~

Insert: 3.3-33-01

NUREG-1431 Markup Inserts
ITS SECTION 3.3.2 - ENGINEERED SAFETY FEATURE ACTUATION SYSTEM (ESFAS) INSTRUMENTATION

Insert: 3.3-33-01

(a) Only as needed to support Manual initiation capability when in MODE 4.

(c) Less than or equal to turbine first stage pressure corresponding to 54.4% full steam flow below 20% load, and increasing linearly from 54.4% full steam flow at 20% load to 110% full steam flow at 100% load, and corresponding to 110% full steam flow above 100% load. Time delay for SI ≤ 6 seconds.

(d) Except when all MSIVs are closed.

(h) Separate Condition entry is allowed for each steam line.

Table 3.3.2-1 (page 3 of 8)
Engineered Safety Feature Actuation System Instrumentation

<CTS>	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	TRIP SETPOINT[a]
	3. Containment Isolation						
	a. Phase A Isolation						
<DOC A.13>	(1) Manual Initiation	1,2,3,4	2	B	SR 3.3.2.~~8~~ 6	NA	NA
<DOC A.14>	(2) Automatic Actuation Logic and Actuation Relays	1,2,3,4 (a)	2 trains	C	SR 3.3.2.2 3 SR 3.3.2.~~4~~ SR 3.3.2.~~6~~ 5	NA	NA
<DOC A.15>	(3) Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.					
	b. Phase B Isolation						
<DOC A.16>	(1) Manual Initiation	1,2,3,4	~~2 per train~~ 2 trains (2)	B	SR 3.3.2.~~8~~ 6	NA	NA
<DOC A.17>	(2) Automatic Actuation Logic and Actuation Relays	1,2,3,4 (a)	2 trains	C	SR 3.3.2.2 3 SR 3.3.2.~~4~~ SR 3.3.2.~~6~~ 5	NA	NA
<DOC A.18>	(3) Containment Pressure ~~High-3~~ (High High)	1,2,3	~~[4]~~ 2 sets of 3	E	SR 3.3.2.1 4 SR 3.3.2.5 SR 3.3.2.~~9~~ 7 ~~SR 3.3.2.10~~	≤ ~~[12.51]~~ 24.3 psig	≤ [12.05] psig
	4. Steam Line Isolation						
<DOC A.19>	a. Manual Initiation	1,2(~~f~~),3(~~f~~)	2 per steam line (2)	F	SR 3.3.2.~~8~~ 6	NA	NA
<DOC A.20>	b. Automatic Actuation Logic and Actuation Relays (d)	1,2(~~f~~),3(~~f~~)	2 trains	G	SR 3.3.2.2 3 SR 3.3.2.~~4~~ SR 3.3.2.~~6~~ 5	NA	NA

(continued)

~~(a) Reviewer's Note: Unit specific implementations may contain only Allowable Value depending on Setpoint Study methodology used by the unit.~~
~~(i) Except when all MSIVs are closed and [de-activated].~~

Insert: 3.3-34-01

NUREG-1431 Markup Inserts
ITS SECTION 3.3.2 - ENGINEERED SAFETY FEATURE ACTUATION SYSTEM (ESFAS) INSTRUMENTATION

Insert: 3.3-34-01

(a) Only as needed to support Manual initiation capability when in MODE 4.

(d) Except when all MSIVs are closed.

Table 3.3.2-1 (page 4 of 8)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	TRIP SETPOINT[a]
4. Steam Line Isolation (continued)						
c. Containment ~~Pressure – High-2~~ (High-High)	1,2[i], 3[i]	2 sets of 3	E	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 ~~SR 3.3.2.10~~	≤ ~~[6.6]~~ 24.3 psig	≤ [6.35] psig
d. Steam Line Pressure						
(1) Low	1,2[i], 3[b][i]	3 per steam line	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≥ [635][c] psig	≥ [675][c] psig
(2) Negative Rate – High	3[g][i]	3 per steam line	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≤ [121.6][h] psi/sec	≤ [110][h] psi/sec
e. High Steam Flow in Two Steam Lines	1,2[i], 3[i]	2 per steam line	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 ~~SR 3.3.2.10~~	(e)	(f)
Coincident with T_{avg} – Low Low	1,2[i], 3[i]	1 per loop	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 ~~SR 3.3.2.10~~	≥ ~~[550.6]~~ 535.6 °F	≥ [553] °F

(continued)

(a) Reviewer's Note: Unit specific implementations may contain only Allowable Value depending on Setpoint Study methodology used by the unit.
(b) Above the P-11 (Pressurizer Pressure) interlock.
(c) Time constants used in the lead/lag controller are $t_1 \geq [50]$ seconds and $t_2 \leq [5]$ seconds.
(d) Above the P-12 (T_{avg} – Low Low) interlock.
(e) Less than or equal to a function defined as ΔP corresponding to [44]% full steam flow below [20]% load, ΔP increasing linearly from [44]% full steam flow at [20]% load to [114]% full steam flow at [100]% load, and ΔP corresponding to [114]% full steam flow above 100% load.
(f) Less than or equal to a function defined as ΔP corresponding to [40]% full steam flow between [0]% and [20]% load and then a ΔP increasing linearly from [40]% steam flow at [20]% load to [110]% full steam flow at [100]% load.
(g) Below the P-11 (Pressurizer Pressure) interlock.
(h) Time constant utilized in the rate/lag controller is ≤ [50] seconds.
(i) Except when all MSIVs are closed and [de-activated].

Insert: 3.3-35-01

NUREG-1431 Markup Inserts
ITS SECTION 3.3.2 - ENGINEERED SAFETY FEATURE ACTUATION SYSTEM (ESFAS) INSTRUMENTATION

Insert: 3.3-35-01

(c) Less than or equal to turbine first stage pressure corresponding to 54.4% full steam flow below 20% load, and increasing linearly from 54.4% full steam flow at 20% load to 110% full steam flow at 100% load, and corresponding to 110% full steam flow above 100% load. Time delay for SI ≤ 6 seconds.

(d) Except when all MSIVs are closed.

(h) Separate Condition entry is allowed for each steam line.

(i) Separate Condition entry is allowed for each loop.

Table 3.3.2-1 (page 5 of 8)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	TRIP SETPOINT[a]
4. Steam Line Isolation (continued)						
⟨DOC A.23⟩ (e) f. High Steam Flow in Two Steam Lines	1,2[(i)], 3[(i)] (d)	2 per steam line	D	SR 3.3.2.1 (4) SR 3.3.2.5 SR 3.3.2.9 ~~SR 3.3.2.10~~ (7)	(d) (e)	(f)
Coincident with Steam Line Pressure – Low	1,2,[(i)], 3[(i)]	1 per steam line	D	SR 3.3.2.1 (4) SR 3.3.2.5 SR 3.3.2.9 ~~SR 3.3.2.10~~ (7)	≥ ~~[635]~~ 476.0 (g) psig	≥ [675] psig (c)
g. High Steam Flow	1,2[(i)], 3[(i)]	2 per steam line	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≤ [25]% of full steam flow at no load steam pressure	≤ [ ] full steam flow at no load steam pressure
Coincident with Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.					
and						
Coincident with T_{avg} – Low Low	1,2[(i)], 3[(d)(i)]	[2] per loop	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≥ [550.6]°F	≥ [553]°F
h. High High Steam Flow	1,2[(i)], 3[(i)]	2 per steam line	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≤ [130]% of full steam flow at full load steam pressure	≤ [ ] of full steam flow at full load steam pressure
Coincident with Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.					—

(continued)

(a) Reviewer's Note: Unit specific implementations may contain only Allowable Value depending on Setpoint Study methodology used by the unit.
(d) Above the P-12 (T_{avg} – Low Low) interlock.
(i) Except when all MSIVs are closed and [de-activated].

Insert: 3.3-36-01

NUREG-1431 Markup Inserts
ITS SECTION 3.3.2 - ENGINEERED SAFETY FEATURE ACTUATION SYSTEM (ESFAS) INSTRUMENTATION

Insert: 3.3-36-01

(c) Less than or equal to turbine first stage pressure corresponding to 54.4% full steam flow below 20% load, and increasing linearly from 54.4% full steam flow at 20% load to 110% full steam flow at 100% load, and corresponding to 110% full steam flow above 100% load. Time delay for SI ≤ 6 seconds.

(d) Except when all MSIVs are closed.

Table 3.3.2-1 (page 6 of 8)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	TRIP SETPOINT[a]
5. Turbine Trip and Feedwater Isolation						
a. Automatic Actuation Logic and Actuation Relays	1,2[h], [3][d]	2 trains	H ~~H[c]~~	SR 3.3.2.2 ~~SR 3.3.2.4~~ SR 3.3.2.6	NA	NA
b. SG Water Level – High High (P-14)	1,2[j], [3][j]	[3] per SG	I [D]	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 ~~SR 3.3.2.10~~	≤ [84.2]%	≤ [82.6]%
c. Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.					
6. Auxiliary Feedwater						
a. Automatic Actuation Logic and Actuation Relays ~~(Solid State Protection System)~~	1,2,3	2 trains	G	SR 3.3.2.2 ~~SR 3.3.2.4~~ SR 3.3.2.6	NA	NA
b. Automatic Actuation Logic and Actuation Relays (Balance of Plant ESFAS)	1,2,3	2 trains	G	SR 3.3.2.3	NA	NA
c. SG Water Level – Low Low	1,2,3	[3] per SG	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 ~~SR 3.3.2.10~~	≥ [30.6]% 3.54% NR	≥ [32.2]%

(continued)

(a) Reviewer's Note: Unit specific implementations may contain only Allowable Value depending on Setpoint Study methodology used by the unit.
(j) Except when all MFIVs, MFRVs, [and associated bypass valves] are closed and [de-activated] [or isolated by a closed manual valve].

Insert 3.3-37-01

NUREG-1431 Markup Inserts
ITS SECTION 3.3.2 - ENGINEERED SAFETY FEATURE ACTUATION SYSTEM (ESFAS) INSTRUMENTATION

Insert: 3.3-37-01

(f) Except when all MBFPDVs or MBFRVs and associated bypass valves are closed or isolated by a closed manual valve.

(J) Separate Condition entry is allowed for each SG.

Table 3.3.2-1 (page 7 of 8)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	TRIP SETPOINT[a]
6. Auxiliary Feedwater (continued) (g)						
(DOC 27) (c) ~~d.~~ Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.					
(DOC 28) (d) ~~e.~~ Loss of Offsite Power (Insert: 3.3-38-01)	1,2,3 (1 per bus (2 buses))	[3] per bus	F	SR 3.3.2.7 (6) SR 3.3.2.9 (7) ~~SR 3.3.2.10~~	≥ [2972] (200) V with ≤ 0.8 sec time delay	≥ [2975] V with ≤ 0.8 sec time delay
~~f. Undervoltage Reactor Coolant Pump~~	~~1,2~~	~~[3] per bus~~	~~I~~	~~SR 3.3.2.7 SR 3.3.2.9 SR 3.3.2.10~~	~~≥ [69]% bus voltage~~	~~≥ [70]% bus voltage~~
(DOC 29) (e) ~~g.~~ Trip of ~~all~~ Main Feedwater Pumps (Boiler)	~~1,2~~	[2] per pump (1 per MBFP)	~~J~~ I	SR 3.3.2.8 (6) ~~SR 3.3.2.9~~ ~~SR 3.3.2.10~~	≥ [ ] psig (NA)	≥ [ ] psig
~~h. Auxiliary Feedwater Pump Suction Transfer on Suction Pressure – Low~~	~~1,2,3~~	~~[2]~~	~~F~~	~~SR 3.3.2.1 SR 3.3.2.7 SR 3.3.2.9~~	~~≥ [20.5] [psia]~~	~~≥ [ ] [psia]~~
7. Automatic Switchover to Containment Sump						
a. Automatic Actuation Logic and Actuation Relays	1,2,3,4	2 trains	C	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.6	NA	NA
b. Refueling Water Storage Tank (RWST) Level – Low Low	1,2,3,4	4	K	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≥ [15]% and ≤ [ ]%	≥ [ ] and ≤ [ ]
Coincident with Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.					
						(continued)

(a) Reviewer's Note: Unit specific implementations may contain only Allowable Value depending on Setpoint Study methodology used by the unit. (Insert: 3.3-38-02)

NUREG-1431 Markup Inserts
ITS SECTION 3.3.2 - ENGINEERED SAFETY FEATURE ACTUATION SYSTEM (ESFAS) INSTRUMENTATION

Insert: 3.3-38-01

(Non SI Blackout Sequence Signal)

Insert: 3.3-38-01

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

(g) Not required if AFW pump not required to be OPERABLE.

Table 3.3.2-1 (page 8 of 8)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	TRIP SETPOINT[a]
7. Automatic Switchover to Containment Sump (continued)						
c. RWST Level – Low Low	1,2,3,4	4	K	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≥ [15]%	≥ [18]%
Coincident with Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.					
and						
Coincident with Containment Sump Level – High	1,2,3,4	4	K	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≥ [30] in. above el. [703] ft	≥ [ ] in. above el. [ ] ft
7 ~~8.~~ ESFAS Interlocks –						
a. Reactor Trip, P-4	1,2,3	1 per train, 2 trains	F	SR 3.3.2.11	NA	NA
b. Pressurizer Pressure, P-11	1,2,3	3	~~L~~ K	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9	≤ [1996] psig (1998.24)	≤ [ ] psig
c. T_{avg} – Low Low, P-12	1,2,3	[1] per loop	L	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9	≥ [550.6]°F	≥ [553]°F

(a) Reviewer's Note: Unit specific implementations may contain only Allowable Value depending on Setpoint Study methodology used by the unit.

B 3.3 INSTRUMENTATION

B 3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

BASES

BACKGROUND

The ESFAS initiates necessary safety systems, based on the values of selected unit parameters, to protect against violating core design limits and the Reactor Coolant System (RCS) pressure boundary, and to mitigate accidents.

The ESFAS instrumentation is segmented into three distinct but interconnected modules as identified below:

- Field transmitters or process sensors and instrumentation: provide a measurable electronic signal based on the physical characteristics of the parameter being measured;
- Signal processing equipment including analog protection system, field contacts, and protection channel sets: provide signal conditioning, bistable setpoint comparison, process algorithm actuation, compatible electrical signal output to protection system devices, and control board/control room/ miscellaneous indications; and
- ~~Solid State Protection System (SSPS) including input, logic, and output bays~~: initiates the proper ~~unit shutdown or~~ engineered safety feature (ESF) actuation in accordance with the defined logic and based on the bistable outputs from the signal process control and protection system.

ESFAS automatic initiation relay logic

Field Transmitters or Sensors

RPS

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 ESFAS are shared with the Reactor Trip System (RTS). In some cases, the same channels also provide control system inputs. To account for calibration tolerances and instrument drift, which are assumed to occur between calibrations, statistical allowances are provided in the Trip Setpoint and Allowable

Protection

(continued)

BASES

BACKGROUND

Field Transmitters or Sensors (continued)

Values. The OPERABILITY of each transmitter or sensor can be evaluated when its "as found" calibration data are compared against its documented acceptance criteria.

Signal Processing Equipment

Generally, three or four channels of process control equipment are used for the signal processing of unit parameters measured by the field instruments. The process control equipment provides signal conditioning, comparable output signals for instruments located on the main control board, and comparison of measured input signals with setpoints established by safety analyses. These setpoints are defined in FSAR, Chapter [6] (Ref. 1), Chapter [7] (Ref. 2), and Chapter [15] (Ref. 3). If the measured value of a unit parameter exceeds the predetermined setpoint, an output from a bistable is forwarded to the SSPS for decision evaluation. Channel separation is maintained up to and through the input bays. However, not all unit parameters require four channels of sensor measurement and signal processing. Some unit parameters provide input only to the SSPS, while others provide input to the SSPS, the main control board, the unit computer, and one or more control systems.

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ESFAS relay logic

Generally, if a parameter is used only for input to the protection circuits, three channels with a two-out-of-three logic are sufficient to provide the required reliability and redundancy. If one channel fails in a direction that would not result in a partial Function trip, the Function is still OPERABLE with a two-out-of-two logic. If one channel fails such that a partial Function trip occurs, a trip will not occur and the Function is still OPERABLE with a one-out-of-two logic.

Generally, if a parameter is used for input to the SSPS and a control function, four channels with a two-out-of-four logic are sufficient to provide the required reliability and redundancy. The circuit ~~must be able~~ is designed to withstand both an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function

(continued)

BASES

BACKGROUND

Signal Processing Equipment (continued)

actuation. Again, a single failure will neither cause nor prevent the protection function actuation.

These requirements are described in IEEE-279-1971 (Ref. 4). The actual number of channels required for each unit parameter is specified in Reference 2.

1968

and discussed later in these Technical Specification Bases

Trip Setpoints and Allowable Values

~~The Trip Setpoints are the nominal values at which the bistables are set. Any bistable is considered to be properly adjusted when the "as left" value is within the band for CHANNEL CALIBRATION accuracy.~~

~~The Trip Setpoints used in the bistables are based on the analytical limits stated in Reference 2. The selection of these Trip Setpoints is such that adequate protection is provided when all sensor and processing time delays are taken into account. To allow for calibration tolerances, instrumentation uncertainties, instrument drift, and severe environment errors for those ESFAS channels that must function in harsh environments as defined by 10 CFR 50.49 (Ref. 5), the Trip Setpoints and Allowable Values specified in Table 3.3.2-1 in the accompanying LCO are conservatively adjusted with respect to the analytical limits. A detailed description of the methodology used to calculate the Trip Setpoints, including their explicit uncertainties, is provided in the "RTS/ESFAS Setpoint Methodology Study" (Ref. 6). The actual nominal Trip Setpoint entered into the bistable is more conservative than that specified by the Allowable Value to account for changes in random measurement errors detectable by a COT. One example of such a change in measurement error is drift during the surveillance interval. If the measured setpoint does not exceed the Allowable Value, the bistable is considered OPERABLE.~~

Insert: B 3.3-63-01

Setpoints in accordance with the Allowable Value ensure that the consequences of Design Basis Accidents (DBAs) will be acceptable, providing the unit is operated from within the LCOs at the onset of the DBA and the equipment functions as designed.

(continued)

NUREG-1431 Markup Inserts
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INSERT B 3.3-63-01:

The following describes the relationship between the safety limit, analytical limit, allowable value and channel component calibration acceptance criteria:

a. A Safety Limit (SL) is a limit on the combination of THERMAL POWER, RCS highest loop average temperature, and RCS pressure needed to protect the integrity of physical barriers that guard against the uncontrolled release of radioactivity (i.e., fuel, fuel cladding, RCS pressure boundary and containment). The safety limits are identified in Technical Specification 2.0, Safety Limits (SLs).

b. An Analytical Limit (AL) is the trip actuation point used as an input to the accident analyses presented in FSAR, Chapter 14 (Ref. 3). Analytical limits are developed from event analyses models which consider parameters such as process delays, rod insertion times, reactivity changes, instrument response times, etc. An analytical limit for a trip actuation point is established at a point that will ensure that a Safety Limit (SL) is not exceeded.

c. An Allowable Value (AV) is the limiting actuation point for the entire channel of a trip function that will ensure, within the required level of confidence, that sufficient allocation exists between this actual trip function actuation point and the analytical limit. The Allowable Value is more conservative than the Analytical Limit to account for instrument uncertainties that either are not present or are not measured during periodic testing. Channel uncertainties that either are not present or are not measured during periodic testing may include design basis accident temperature and radiation effects (Ref. 5) or process dependent effects. The channel allowable value for each RPS function is controlled by Technical Specifications and is listed in Table 3.3.1-1, Reactor Protection System Instrumentation.

d. Calibration acceptance criteria (i.e., setpoints) are established by plant administrative programs for the components of a channel (i.e., required sensor, alarm, interlock, display, and trip function). The calibration acceptance criteria are established to ensure, within the required level of confidence, that the Allowable Value for the entire channel will not be exceeded during the calibration interval.

A description of the methodology used to calculate the channel allowable values and calibration acceptance criteria is provided in References 6 and 8.

BASES

BACKGROUND

Trip Setpoints and Allowable Values (continued)

required to be OPERABLE

Each channel can be tested on line to verify that the signal processing equipment and setpoint accuracy is within the specified allowance requirements of Reference 2. Once a designated channel is taken out of service for testing, a simulated signal is injected in place of the field instrument signal. The process equipment for the channel in test is then tested, verified, and calibrated. SRs for the channels are specified in the SR section.

Insert: B 3.3-64-01

Insert: B 3.3-64-02

The ~~Trip Setpoints and~~ Allowable Values listed in Table 3.3.2-1 are based on the methodology described in ~~Reference 6, which incorporates all of the known uncertainties applicable for each channel. The magnitudes of these uncertainties are factored into the determination of each Trip Setpoint.~~ All field sensors and signal processing equipment for these channels are assumed to operate within the allowances of these uncertainty magnitudes.

ESFAS Relay Logic

~~Solid State~~ Protection System

relay logic

The SSPS equipment is used for the decision logic processing of outputs from the signal processing equipment bistables. To meet the redundancy requirements, two trains of SSPS, each performing the same functions, are provided. If one train is taken out of service for maintenance or test purposes, the second train will provide ESF actuation for the unit. ~~If both trains are taken out of service or placed in test, a reactor trip will result.~~ Each train is packaged in ~~its own~~ cabinet for physical and electrical separation to satisfy separation and independence requirements.

The SSPS performs the decision logic for most ESF equipment actuation; generates the electrical output signals that initiate the required actuation; and provides the status, permissive, and annunciator output signals to the main control room ~~of the unit~~.

The bistable outputs from the signal processing equipment are sensed by the SSPS equipment and combined into logic ~~matrices~~ that represent combinations indicative of various

(continued)

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INSERT B 3.3-64-01:

and the Trip Setpoints calculated to ensure that Allowable Values are not exceeded during the calibration interval

INSERT B 3.3-64-02:

calculations performed in accordance with Reference 6.

BASES

BACKGROUND

Solid State Protection System (continued)

ESFAS Relay Logic

transients. If a required logic ~~matrix~~ combination is completed, the system will send actuation signals via master and slave relays to those components whose aggregate Function best serves to alleviate the condition and restore the unit to a safe condition. Examples are given in the Applicable Safety Analyses, LCO, and Applicability sections of this Bases.

relay logic

capability

Each SSPS train has a built in testing device that can automatically test the decision logic matrix functions and the actuation devices while the unit is at power. When any one train is taken out of service for testing, the other train is capable of providing unit monitoring and protection until the testing has been completed. The testing device is semiautomatic to minimize testing time.

The actuation of ESF components is accomplished through master and slave relays. The SSPS energizes the master relays appropriate for the condition of the unit. Each master relay then energizes one or more slave relays, which then cause actuation of the end devices. The master and slave relays are routinely tested to ensure operation. The test of the master relays energizes the relay, which then operates the contacts and applies a low voltage to the associated slave relays. The low voltage is not sufficient to actuate the slave relays but only demonstrates signal path continuity. The SLAVE RELAY TEST actuates the devices if their operation will not interfere with continued unit operation. For the latter case, actual component operation is prevented by the SLAVE RELAY TEST circuit, and slave relay contact operation is verified by a continuity check of the circuit containing the slave relay.

Reviewer's Note: No one unit ESFAS incorporates all of the Functions listed in Table 3.3.2-1. In some cases (e.g., Containment Pressure—High 3, Function 2.c), the table reflects several different implementations of the same Function. Typically, only one of these implementations are used at any specific unit.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

Each of the analyzed accidents can be detected by one or more ESFAS Functions. One of the ESFAS Functions is the primary actuation signal for that accident. An ESFAS Function may be the primary actuation signal for more than one type of accident. An ESFAS Function may also be a secondary, or backup, actuation signal for one or more other accidents. For example, Pressurizer Pressure—Low is a primary actuation signal for small loss of coolant accidents (LOCAs) and a backup actuation signal for 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).

identified in Table 3.3.2-1

The LCO requires all instrumentation performing an ESFAS Function to be OPERABLE. 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. Safety Injection

   Safety Injection (SI) provides two primary functions:

   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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1. Safety Injection (continued)

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

These functions are necessary to mitigate the effects of high energy line breaks (HELBs) both inside and outside of containment. The SI signal is also used to initiate other Functions such as:

- Phase A Isolation;
- Containment Purge Isolation;
- Reactor Trip;
- Turbine Trip;
- Feedwater Isolation;
- Start of motor driven auxiliary feedwater (AFW) pumps; and
- Control room ventilation isolation; ~~and~~.
- ~~Enabling automatic switchover of Emergency Core Cooling Systems (ECCS) suction to containment sump.~~

actuation to the 10% incident mode

These other functions ensure:

- Isolation of nonessential systems through containment penetrations;
- Trip of the turbine and reactor to limit power generation;
- Isolation of main feedwater (MFW) to limit secondary side mass losses;
- Start of AFW to ensure secondary side cooling capability; and
- Isolation of the control room to ensure habitability; ~~and~~.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1. Safety Injection (continued)

- Enabling ECCS suction from the refueling water storage tank (RWST) switchover on low low RWST level to ensure continued cooling via use of the containment sump.

a. Safety Injection—Manual Initiation

The LCO requires one channel per train to be OPERABLE. The operator can initiate both trains of SI at any time by using either of two switches push buttons in the control room. This action will cause actuation of all components in the same manner as any of the automatic actuation signals.

The LCO for the Manual Initiation Function ensures the proper amount of redundancy is maintained in the manual ESFAS actuation circuitry to ensure the operator has manual ESFAS initiation capability.

Each channel consists of one push button and the interconnecting wiring to the actuation logic cabinet. Each push button actuates both trains. This configuration does not allow testing at power.

b. Safety Injection—Automatic Actuation Logic and Actuation Relays

This LCO requires two trains to be OPERABLE. Actuation logic consists of all circuitry housed within the actuation subsystems, including the initiating relay contacts responsible for actuating the ESF equipment.

Manual and automatic initiation of SI must be OPERABLE in MODES 1, 2, and 3. In these MODES, there is sufficient energy in the primary and secondary systems to warrant automatic initiation of ESF systems. 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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. Safety Injection—Automatic Actuation Logic and Actuation Relays (continued)

because of the large number of components actuated on a SI, actuation is simplified by the use of the manual actuation push buttons. Automatic actuation logic and actuation relays must be OPERABLE in MODE 4 as needed to support system level manual initiation.

These Functions are not required to be OPERABLE in MODES 5 and 6 because there is adequate time for the operator to evaluate unit conditions and respond by manually starting individual systems, pumps, and other equipment to mitigate the consequences of an abnormal condition or accident. Unit pressure and temperature are very low and many ESF components are administratively locked out or otherwise prevented from actuating to prevent inadvertent overpressurization of unit systems.

c. Safety Injection—Containment Pressure—High X

This signal provides protection against the following accidents:

- SLB inside containment; and
- LOCA; ~~and~~
- ~~Feed line break inside containment.~~

Containment Pressure—High X provides no input to any control functions. Thus, three OPERABLE channels are sufficient to satisfy protective requirements with a two-out-of-three logic. The transmitters (d/p cells) and electronics are located outside of containment with the sensing line (high pressure side of the transmitter) located inside containment.

Thus, the high pressure Function will not experience any adverse environmental conditions and the Trip Setpoint reflects only steady state instrument uncertainties.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

c. Safety Injection—Containment Pressure—High (continued)

Containment Pressure—High must be OPERABLE in MODES 1, 2, and 3 when there is sufficient energy in the primary and secondary systems to pressurize the containment following a pipe break. In MODES 4, 5, and 6, there is insufficient energy in the primary or secondary systems to pressurize the containment.

d. Safety Injection—Pressurizer Pressure—Low

This signal provides protection against the following accidents:

- Inadvertent opening of a steam generator (SG) relief or safety valve;
- SLB;
- ~~A spectrum of rod cluster control assembly ejection accidents (rod ejection);~~
- Inadvertent opening of a pressurizer relief or safety valve;
- LOCAs; and
- SG Tube Rupture.

Insert: B 3.3-70-01

~~At some units pressurizer pressure provides both control and protection functions: input to the Pressurizer Pressure Control System, reactor trip, and SI. Therefore, the actuation logic must be able to withstand both an input failure to control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Thus, four OPERABLE channels are required to satisfy the requirements with a two-out-of-four logic. For units that have dedicated protection and control channels, only three protection channels are necessary to satisfy the protective requirements.~~

(continued)

NUREG-1431 Markup Inserts
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INSERT: B 3.3-70-01

Three channels of pressurizer pressure provide input into the ESFAS actuation logic. These channels initiate the ESFAS automatically when two of the three channels exceed the low pressure setpoint. These protection channels also provide control functions; however, the two-out-of-three logic is considered adequate to provide the required protection.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

d. Safety Injection—Pressurizer Pressure—Low (continued)

The transmitters are located inside containment, with the taps in the vapor space region of the pressurizer, and thus possibly experiencing adverse environmental conditions (LOCA, SLB inside containment, rod ejection). Therefore, the Trip Setpoint reflects the inclusion of both steady state and adverse environmental instrument uncertainties.

the Pressurizer Pressure Interlock (Function 7)

This Function must be OPERABLE in MODES 1, 2, and 3 (above P-11) to mitigate the consequences of an HELB inside containment. This signal may be manually blocked by the operator below the P-11 setpoint. Automatic SI actuation below this pressure setpoint is ~~then~~ performed by the Containment Pressure—High 2 signal.

This Function is not required to be OPERABLE in MODE 3 below the P-11 setpoint. Other ESF functions are used to detect accident conditions and actuate the ESF systems in this MODE. In MODES 4, 5, and 6, this Function is not needed for accident detection and mitigation.

e. Safety Injection—Steam Line Pressure

(1) Steam Line Pressure—Low

Steam Line Pressure—Low provides protection against the following accidents:

- SLB;
- Feed line break; and
- Inadvertent opening of an SG relief or an SG safety valve.

Steam Line Pressure—Low provides no input to any control functions. Thus, three OPERABLE channels on each steam line are sufficient to satisfy the protective

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

(1) Steam Line Pressure—Low (continued)

requirements with a two-out-of-three logic on each steam line.

With the transmitters typically located inside the steam tunnels, it is possible for them to experience adverse environmental conditions during a secondary side break. Therefore, the Trip Setpoint reflects both steady state and adverse environmental instrument uncertainties.

This Function is anticipatory in nature and has a typical lead/lag ratio of 50/5.

Steam Line Pressure—Low must be OPERABLE in MODES 1, 2, and 3 (above P-11) when a secondary side break or stuck open valve could result in the rapid depressurization of the steam lines. This signal may be manually blocked by the operator below the P-11 setpoint. Below P-11, feed line break is not a concern. Inside containment SLB will be terminated by automatic SI actuation via Containment Pressure—High 1, and outside containment SLB will be terminated by the Steam Line Pressure—Negative Rate—High signal for steam line isolation. This Function is not required to be OPERABLE in MODE 4, 5, or 6 because there is insufficient energy in the secondary side of the unit to cause an accident.

(2) Steam Line Pressure—High Differential Pressure Between Steam Lines

Steam Line Pressure—High Differential Pressure Between Steam Lines provides protection against the following accidents:

- SLB; and
- Feed line break, and

(continued)

BASES

Safety Injection

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

(2) ~~Steam Line Pressure~~—High Differential Pressure Between Steam Lines (continued)

- Inadvertent opening of an SG relief or an SG safety valve. ADV

~~Steam Line Pressure~~—High Differential Pressure Between Steam Lines provides no input to any control functions. Thus, three OPERABLE channels on each steam line are sufficient to satisfy the requirements, with a two-out-of-three logic on each steam line.

With the transmitters ~~typically~~ located inside the ~~steam tunnels~~, it is possible for them to experience adverse environmental conditions during an SLB a HELB event. Therefore, the Trip Setpoint reflects both steady state and adverse environmental instrument uncertainties. Steam line high differential pressure must be OPERABLE in MODES 1, 2, and 3 when a secondary side break or stuck open valve could result in the rapid depressurization of the steam line(s). This Function is not required to be OPERABLE in MODE 4, 5, or 6 because there is not sufficient energy in the secondary side of the unit to cause an accident.

auxiliary feed pump room

¶

f, g. Safety Injection—High Steam Flow in Two Steam Lines Coincident With T_{avg}—Low Low or Coincident With Steam Line Pressure—Low

These Functions (1.f and 1.g) provide protection against the following accidents:

- SLB; and
- the inadvertent opening of ~~an SG relief or~~ an SG safety valve. DB.1

Two steam line flow channels per steam line are required OPERABLE for these Functions. The steam line flow channels are combined in a one-out-of-

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

f, g. Safety Injection—High Steam Flow in Two Steam Lines Coincident With T_{avg}—Low (Low) or Coincident With Steam Line Pressure—Low (continued)

two logic to indicate high steam flow in one steam line. The steam flow transmitters provide control inputs, but the control function cannot cause the events that the Function must protect against. Therefore, two channels are sufficient to satisfy redundancy requirements. The one-out-of-two configuration allows online testing because trip of one high steam flow channel is not sufficient to cause initiation. High steam flow in two steam lines is acceptable in the case of a single steam line fault due to the fact that the remaining intact steam lines will pick up the full turbine load. The increased steam flow in the remaining intact lines will actuate the required second high steam flow trip. Additional protection is provided by Function 1.e. (2), High Differential Pressure Between Steam Lines.

One channel of T_{avg} per loop and one channel of low steam line pressure per steam line are required OPERABLE. For each parameter, the channels for all loops or steam lines are combined in a logic such that two channels tripped will cause a trip for the parameter. For example, for three loop units, the low steam line pressure channels are combined in two-out-of-three logic. Thus, the Function trips on one-out-of-two high flow in any two-out-of-three steam lines if there is one-out-of-one low (low) T_{avg} trip in any two-out-of-three RCS loops, or if there is a one-out-of-one low pressure trip in any two-out-of-three steam lines. Since the accidents that this event protects against cause both low steam line pressure and low (low) T_{avg}, provision of one channel per loop or steam line ensures no single random failure can disable both of these Functions. The steam line pressure channels provide no control inputs. The T_{avg} channels provide control inputs, but the control function cannot initiate events that the Function acts to mitigate.

steam

four

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

f, g. Safety Injection—High Steam Flow in Two Steam Lines Coincident With T_{avg}—Low (~~Lag~~) or Coincident With Steam Line Pressure—Low (continued)

The Allowable Value for high steam flow is a linear function that varies with power level. The function is a (ΔP) corresponding to (44%) of full steam flow between 0% and 20% load to (114%) of full steam flow at 100% load. The nominal trip setpoint is similarly calculated.

turbine first stage pressure

approximately 54%

approximately 110%

auxiliary feedwater building

With the transmitters ~~typically~~ located inside the containment (T_{avg}) or inside the steam tunnels (~~High Steam Flow~~), it is possible for them to experience adverse steady state environmental conditions during an SLB event. Therefore, the Trip Setpoint reflects both steady state and adverse environmental instrument uncertainties. ~~The Steam Line Pressure—Low signal was discussed previously under Function 1.e.(1).~~

RCS temperature and steam line flow

Steam Pressure

This Function must be OPERABLE in MODES 1, 2, and 3 (~~above P-12~~) when a secondary side break or stuck open valve could result in the rapid depressurization of the steam line(s). ~~This signal may be manually blocked by the operator when below the P-12 setpoint. Above P-12, this Function is automatically unblocked. This Function is not required OPERABLE below P-12 because the reactor is not critical, so feed line break is not a concern.~~ SLB may be addressed by Containment Pressure High (2) (inside containment) or by High Steam Flow in Two Steam Lines coincident with Steam Line Pressure—Low, for Steam Line Isolation, followed by High Differential Pressure Between Two Steam Lines, for SI. This Function is not required to be OPERABLE in MODE 4, 5, or 6 because there is insufficient energy in the secondary side of the unit to cause an accident.

when any MSIV is open because

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

2. Containment Spray

Containment Spray provides three primary functions:

1. Lowers containment pressure and temperature after an HELB in containment;

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

3. Adjusts the pH of the water in the containment recirculation sump after a large break LOCA.

These functions are necessary to:

- Ensure the pressure boundary integrity of the containment structure;

- Limit the release of radioactive iodine to the environment ~~in the event of a failure of the containment structure~~; and

- Minimize corrosion of the components and systems inside containment following a LOCA.

The containment spray actuation signal starts the containment spray pumps. ~~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 and mixed with a sodium hydroxide solution from the spray additive tank. When the RWST reaches ~~the low low level setpoint~~ a specified minimum level, the spray ~~pump suctions are shifted to the containment sump~~ pumps are secured. RHR or recirculation pumps will be used if continued containment spray is required. Containment spray is actuated ~~manually~~ automatically by ~~Containment Pressure—High 2 or~~ Containment Pressure—High High.

a. Containment Spray—Manual Initiation

Insert: B3.3-76-01

~~The operator can initiate containment spray at any time from the control room by simultaneously turning two containment spray actuation switches in the same train. Because an inadvertent actuation of containment spray could have such serious consequences, two switches must be turned~~

(continued)

NUREG-1431 Markup Inserts
ITS SECTION 3.3.2 - ENGINEERED SAFETY FEATURE ACTUATION SYSTEM (ESFAS) INSTRUMENTATION

INSERT: B 3.3-76-01

Manual initiation of containment spray (CS) requires that two pushbuttons in the control room be depressed simultaneously which will actuate both trains of CS. Two pushbuttons must be depressed simultaneously to minimize the potential for an inadvertent actuation of CS which could have serious consequences. Each CS pushbutton closes one of the two contacts required to start CS train A and one of the two contacts required to start CS train B; depressing both pushbuttons closes both of the contacts required to start CS train A and both of the contacts required to start CS train B. Two channels (contacts) are required to be Operable for CS train A and two channels (contacts) are required to be Operable for CS train B. Failure of one manual pushbutton will result in one inoperable channel in both trains.

Note that Manual Initiation of containment spray also actuates Phase B containment isolation and containment ventilation isolation.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

a. Containment Spray—Manual Initiation (continued)

simultaneously to initiate containment spray. There are two sets of two switches each in the control room. Simultaneously turning the two switches in either set will actuate containment spray in both trains in the same manner as the automatic actuation signal. Two Manual Initiation switches in each train are required to be OPERABLE to ensure no single failure disables the Manual Initiation Function. Note that Manual Initiation of containment spray also actuates Phase B containment isolation.

b. Containment Spray—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 containment spray must be OPERABLE in MODES 1, 2, and 3 when there is a potential for an accident to occur, and sufficient energy in the primary or secondary systems to pose a threat to containment integrity due to overpressure conditions. 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. However, because of the large number of components actuated on a containment spray, 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 and secondary systems to result in containment overpressure. In MODES 5 and 6, there is also adequate time for the operators to evaluate unit conditions and respond, to mitigate the consequences of abnormal conditions by manually starting individual components.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

c. Containment Spray—Containment Pressure

This signal provides protection against a LOCA or an SLB inside containment. The transmitters (d/p cells) are located outside of containment with the sensing line (high pressure side of the transmitter) located inside containment. The transmitters and electronics are located outside of containment. Thus, they will not experience any adverse environmental conditions and the Trip Setpoint reflects only steady state instrument uncertainties.

This ~~is one of the only~~ Function~~s~~ ~~that~~ requires the bistable output to energize to perform its required action. It is not desirable to have a loss of power actuate containment spray, ~~since~~ because the consequences of an inadvertent actuation of containment spray could be serious. ~~Note that this Function also has the inoperable channel placed in bypass rather than trip to decrease the probability of an inadvertent actuation.~~

Insert: B3.3-78-01

~~Two different logic configurations are typically used. Three and four loop units use four channels in a two-out-of-four logic configuration. This configuration may be called the Containment Pressure—High 3 Setpoint for three and four loop units, and Containment Pressure—High High Setpoint for other units. Some two loop units use three sets of two channels, each set combined in a one-out-of-two configuration, with these outputs combined so that two-out-of-three sets tripped initiates containment spray. This configuration is called Containment Pressure—High 3 Setpoint. Since~~ containment pressure is not used for control, ~~both of these~~ arrangements exceed the minimum redundancy requirements. ~~Additional redundancy is warranted because this Function is energize to trip.~~ Containment Pressure ~~[High 3]~~ [High High] must be OPERABLE in MODES 1, 2, and 3 when there is sufficient energy in the primary and secondary sides to pressurize the containment following a pipe break. In MODES 4, 5, and 6, there is insufficient energy in the primary and secondary

Therefore, this

(continued)

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ITS SECTION 3.3.2 - ENGINEERED SAFETY FEATURE ACTUATION SYSTEM (ESFAS) INSTRUMENTATION

INSERT: B 3.3-78-01

Therefore, the IP3 design consists of 2 sets of 3 channels (i.e., 6 pressure instruments) and 2 channels from each set of 3 are required to energize to actuate Containment Spray. This configuration provides sufficient redundancy to prevent a single failure from causing or preventing Containment Spray initiation even when testing with one inoperable channel already in trip. The Required Actions for an inoperable channel associated with this Function decreases the probability of an inadvertent actuation by allowing no more than one channel per set to be placed in trip.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

c. Containment Spray—Containment Pressure (continued)

sides to pressurize the containment and reach the Containment Pressure—High 3 (High High) setpoints.

3. Containment Isolation

Containment Isolation provides selected isolation of the containment atmosphere, and ~~all~~ process systems that penetrate containment, ~~from the environment~~. This Function is necessary to prevent or limit the release of radioactivity to the environment in the event of a large break LOCA.

There are two separate Containment Isolation signals, Phase A and Phase B. Phase A isolation isolates all automatically isolable process lines, except component cooling water (CCW), at a relatively low containment pressure indicative of primary or secondary system leaks. For these types of events, forced circulation cooling using the reactor coolant pumps (RCPs) and SGs is the preferred (but not required) method of decay heat removal. Since CCW is required to support RCP operation, not isolating CCW on the low pressure Phase A signal enhances unit safety by allowing operators to use forced RCS circulation to cool the unit. Isolating CCW on the low pressure signal may force the use of feed and bleed cooling, which could prove more difficult to control.

Phase A containment isolation is actuated automatically by SI, or manually via the ~~automatic~~ actuation logic. All process lines penetrating containment, with the exception of CCW, are isolated. CCW is not isolated at this time to permit continued operation of the RCPs with cooling water flow to the thermal barrier heat exchangers and ~~air or~~ oil coolers. All process lines not equipped with remote operated isolation valves are manually closed, or otherwise isolated, prior to ~~reaching~~ MODE 4.

Manual Phase A Containment Isolation is accomplished by either of two switches in the control room. Either switch actuates both trains. Note that manual

(continued)

and RCP seal return

RCP seal injection and return are

these functions

are

except those manual isolation valves needed to support plant operations

pushbutton

pushbuttons

exiting containment

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3. Containment Isolation (continued)

actuation of Phase A Containment Ventilation Isolation also actuates Containment ~~Purge and Exhaust~~ Isolation.

The Phase B signal isolates CCW and RCP seal return. This occurs at a relatively high containment pressure that is indicative of a large break LOCA or an SLB. For these events, forced circulation using the RCPs is no longer desirable. Isolating the CCW at the higher pressure does not pose a challenge to the containment boundary because the CCW System is a closed loop inside containment. Although some CCW system components ~~do~~ may not meet all of the ASME Code requirements applied to the containment itself, the system is continuously pressurized to a pressure greater than the Phase B setpoint. Thus, routine operation demonstrates the integrity of the system pressure boundary for pressures exceeding the Phase B setpoint. Furthermore, because system pressure exceeds the Phase B setpoint, any system leakage prior to initiation of Phase B isolation would be into containment. Therefore, the combination of CCW System design and Phase B isolation ensures the CCW System is not a potential path for radioactive release from containment.

Phase B containment isolation is actuated by ~~Containment Pressure—High 3 or~~ Containment Pressure—High High, or manually, via the ~~automatic~~ actuation logic, as previously discussed. For containment pressure to reach a value high enough to actuate ~~Containment Pressure—High 3 or~~ Containment Pressure—High High, a large break LOCA or SLB must have occurred and containment spray must have been actuated. RCP operation will no longer be required and CCW and seal return to the RCPs ~~is~~ are, therefore, no longer necessary. The RCPs can be operated with seal injection flow alone and without CCW flow to the thermal barrier heat exchanger.

Insert B 3.3-80-01

Manual Phase B Containment Isolation is ~~accomplished~~ also initiated by ~~the same switches that actuate~~ Containment Spray. When the two ~~switches in either set are turned~~ CS pushbuttons are depressed simultaneously, Phase B Containment Isolation and Containment Spray will be actuated in both trains. manual pushbuttons

(continued)

NUREG-1431 Markup Inserts
ITS SECTION

INSERT: B 3.3-80-01

Manual Phase B Containment Isolation is accomplished by either of two pushbuttons in the control room. Either pushbutton actuates both trains.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

a. Containment Isolation—Phase A Isolation

(1) Phase A Isolation—Manual Initiation

Manual Phase A Containment Isolation is actuated by either of two switches in the control room. Either switch actuates both trains. Note that manual initiation of Phase A Containment Isolation also actuates Containment Purge Isolation.

(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 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.

(3) Phase A Isolation—Safety Injection

Phase A Containment Isolation is also initiated by all Functions that initiate SI. The Phase A Containment Isolation

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

(3) Phase A Isolation—Safety Injection (continued)

requirements for these 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.

b. Containment Isolation—Phase B Isolation

Phase B Containment Isolation is accomplished by Manual Initiation, Automatic Actuation Logic and Actuation Relays, and by Containment Pressure channels (the same channels that actuate Containment Spray, Function 2). The Containment Pressure trip of Phase B Containment Isolation is energized to trip in order to minimize the potential of spurious trips that may damage the RCPs.

Insert B3.3-82-01

(1) Phase B Isolation—Manual Initiation

(2) Phase B Isolation—Automatic Actuation Logic and Actuation Relays

Manual and automatic initiation of Phase B 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. However, because of the large number of components actuated on a Phase B 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 B containment

(continued)

NUREG-1431 Markup Inserts
ITS SECTION 3.3.2 - ENGINEERED SAFETY FEATURE ACTUATION SYSTEM (ESFAS) INSTRUMENTATION

INSERT: B 3.3-82-01

Manual Phase B Containment Isolation is accomplished by either of two pushbuttons in the control room. Either pushbutton actuates both trains.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

(1) ~~Phase B Isolation—Manual Initiation~~

(2) Phase B Isolation—Automatic Actuation Logic and Actuation Relays (continued)

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.

(3) Phase B Isolation—Containment Pressure

The basis for containment pressure MODE applicability is as discussed for ESFAS Function 2.c above.

4. Steam Line Isolation

Isolation of the main steam lines provides protection in the event of an SLB inside or outside containment. Rapid isolation of the steam lines will limit the steam break accident to the blowdown from one SG, ~~at~~ most. For an SLB upstream of the main steam isolation valves (MSIVs), inside or outside of containment, closure of the MSIVs limits the accident to the blowdown from only the affected SG. For an SLB downstream of the MSIVs, closure of the MSIVs terminates the accident ~~as soon as the steam lines depressurize. For units that do not have steam line check valves, Steam Line Isolation also mitigates the effects of a feed line break and ensures a source of steam for the turbine driven AFW pump during a feed line break.~~

even if a Main Steam Check Valve fails.

a. Steam Line Isolation—Manual Initiation

Manual initiation of Steam Line Isolation can be accomplished from the control room. ~~There are two switches in the control room and either switch can initiate action to immediately close all MSIVs. The LCO requires two channels to be OPERABLE.~~

Insert: B3.3-83-01

(continued)

NUREG-1431 Markup Inserts
ITS SECTION 3.3.2 - ENGINEERED SAFETY FEATURE ACTUATION SYSTEM (ESFAS) INSTRUMENTATION

INSERT: B 3.3-83-01

Each main steam isolation valve (MSIV) will close if either of two solenoid valves in parallel (channel A and channel B) are opened. The pair of solenoid valves associated with each MSIV are operated by a single switch and there is a separate switch for each MSIV. Each of these switches actuates two channels. Except for the switch in the control room which is common to both channels, there are two separate and redundant circuits (channel A and channel B) capable of closing each MSIV. Therefore, the LCO requires 2 channels per MSIV and each MSIV is considered a separate Function.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

b. Steam Line 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 steam line isolation must be OPERABLE in MODES 1, 2, and 3 when there is sufficient energy in the RCS and SGs to have an SLB or other accident. This could result in the release of significant quantities of energy and cause a cooldown of the primary system. The Steam Line Isolation Function is required in MODES 2 and 3 unless all MSIVs are closed ~~and de-activated~~. In MODES 4, 5, and 6, there is insufficient energy in the RCS and SGs to experience an SLB or other accident releasing significant quantities of energy.

c. Steam Line Isolation—Containment Pressure—High 2 (High-High)

This Function actuates closure of the MSIVs in the event of a LOCA or an SLB inside containment ~~to maintain at least one unfaulted SG as a heat sink for the reactor, and~~ to limit the mass and energy release to containment. The transmitters (d/p cells) are located outside containment ~~with the sensing line (high pressure side of the transmitter) located inside containment~~. Containment Pressure—High 2 ~~provides no input to any control functions. Thus, three OPERABLE channels are sufficient to satisfy protective requirements with two-out-of-three logic. However, for enhanced reliability, this Function was designed with four channels and a two-out-of-four logic.~~ The transmitters and electronics are located outside of containment. Thus, they will not experience any adverse environmental conditions, and the Trip Setpoint reflects only steady state instrument uncertainties.

Insert: B 3.3-84-01

Containment Pressure—High 2 must be OPERABLE in MODES 1, 2, and 3, when there is sufficient energy in the primary and secondary side to pressurize the containment following a pipe

(continued)

INSERT: B 3.3-84-01

The IP3 design consists of 2 sets of 3 channels and 2 channels from each set of 3 are required to energize to actuate steam line isolation on high pressure in the containment. This is the same logic that initiates Containment Spray. Therefore, this logic is designed to provide sufficient redundancy to prevent a single failure from causing or preventing Containment Spray initiation even when testing with one inoperable channel already in trip. The Required Action for an inoperable channel associated with this Function permits no more than one channel per set to be placed in trip to decrease the probability of an inadvertent actuation.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

c. Steam Line Isolation—Containment Pressure—High 2 (High-High)
(continued)

break. This would cause a significant increase in the containment pressure, thus allowing detection and closure of the MSIVs. The Steam Line Isolation Function remains OPERABLE in MODES 2 and 3 unless all MSIVs are closed and ~~de-activated~~. In MODES 4, 5, and 6, there is not enough energy in the primary and secondary sides to pressurize the containment to the Containment Pressure—High 2 setpoint.

d. Steam Line Isolation—Steam Line Pressure

(1) Steam Line Pressure—Low

Steam Line Pressure—Low provides closure of the MSIVs in the event of an SLB to maintain at least one unfaulted SG as a heat sink for the reactor, and to limit the mass and energy release to containment. This Function provides closure of the MSIVs in the event of a feed line break to ensure a supply of steam for the turbine driven AFW pump. Steam Line Pressure—Low was discussed previously under SI Function 1.e.1.

Steam Line Pressure—Low Function must be OPERABLE in MODES 1, 2, and 3 (above P-11), with any main steam valve open, when a secondary side break or stuck open valve could result in the rapid depressurization of the steam lines. This signal may be manually blocked by the operator below the P-11 setpoint. Below P-11, an inside containment SLB will be terminated by automatic actuation via Containment Pressure—High 2. Stuck valve transients and outside containment SLBs will be terminated by the Steam Line Pressure—Negative Rate—High signal for Steam Line Isolation below P-11 when SI has been manually blocked. The Steam Line Isolation Function is required in MODES 2

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

(1) Steam Line Pressure—Low (continued)

and 3 unless all MSIVs are closed and [de-activated]. This Function is not required to be OPERABLE in MODES 4, 5, and 6 because there is insufficient energy in the secondary side of the unit to have an accident.

(2) Steam Line Pressure—Negative Rate—High

Steam Line Pressure—Negative Rate—High provides closure of the MSIVs for an SLB when less than the P-11 setpoint, to maintain at least one unfaulted SG as a heat sink for the reactor, and to limit the mass and energy release to containment. When the operator manually blocks the Steam Line Pressure—Low main steam isolation signal when less than the P-11 setpoint, the Steam Line Pressure—Negative Rate—High signal is automatically enabled. Steam Line Pressure—Negative Rate—High provides no input to any control functions. Thus, three OPERABLE channels are sufficient to satisfy requirements with a two-out-of-three logic on each steam line.

Steam Line Pressure—Negative Rate—High must be OPERABLE in MODE 3 when less than the P-11 setpoint, when a secondary side break or stuck open valve could result in the rapid depressurization of the steam line(s). In MODES 1 and 2, and in MODE 3, when above the P-11 setpoint, this signal is automatically disabled and the Steam Line Pressure—Low signal is automatically enabled. The Steam Line Isolation Function is required to be OPERABLE in MODES 2 and 3 unless all MSIVs are closed and [de-activated]. In MODES 4, 5, and 6, there is insufficient energy in the primary and secondary sides to have an SLB or other accident that would result in a release of significant enough quantities of energy to cause a cooldown of the RCS.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

(2) Steam Line Pressure—Negative Rate—High (continued)

While the transmitters may experience elevated ambient temperatures due to an SLB, the trip function is based on rate of change, not the absolute accuracy of the indicated steam pressure. Therefore, the Trip Setpoint reflects only steady state instrument uncertainties.

d, e ~~e, f.~~ Steam Line Isolation—High Steam Flow in Two Steam Lines Coincident with T_{avg}—Low ~~Low~~ or Coincident With Steam Line Pressure—Low (Three and Four Loop Units)

These Functions (4.~~e~~ d and 4.~~f~~ e) provide closure of the MSIVs during an SLB or inadvertent opening of an SG relief or a safety valve, to maintain at least one unfaulted SG as a heat sink for the reactor and to limit the mass and energy release to containment. RCS cooldown and

These Functions were discussed previously as Functions 1.~~f~~ e and 1.~~g~~ f.

These Functions must be OPERABLE in MODES 1 and 2, and in MODE 3, when a secondary side break or stuck open valve could result in the rapid depressurization of the steam lines unless all MSIVs are closed and de-activated. These Functions are not required to be OPERABLE in MODES 4, 5, and 6 because there is insufficient energy in the secondary side of the unit to have an accident.

g. Steam Line Isolation—High Steam Flow Coincident With Safety Injection and Coincident With T_{avg}—Low Low (Two Loop Units)

This Function provides closure of the MSIVs during an SLB or inadvertent opening of an SG relief or safety valve to maintain at least one unfaulted SG as a heat sink for the reactor, and to limit the mass and energy release to containment.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

g. Steam Line Isolation—High Steam Flow Coincident With Safety Injection and Coincident With T_{avg}—Low Low (Two Loop Units) (continued)

Two steam line flow channels per steam line are required OPERABLE for this Function. These are combined in a one-out-of-two logic to indicate high steam flow in one steam line. The steam flow transmitters provide control inputs, but the control function cannot cause the events that the function must protect against. Therefore, two channels are sufficient to satisfy redundancy requirements. The one-out-of-two configuration allows online testing because trip of one high steam flow channel is not sufficient to cause initiation.

The High Steam Flow Allowable Value is a ΔP corresponding to 25% of full steam flow at no load steam pressure. The Trip Setpoint is similarly calculated.

With the transmitters (d/p cells) typically located inside the steam tunnels, it is possible for them to experience adverse environmental conditions during an SLB event. Therefore, the Trip Setpoints reflect both steady state and adverse environmental instrument uncertainties.

The main steam line isolates only if the high steam flow signal occurs coincident with an SI and low low RCS average temperature. The Main Steam Line Isolation Function requirements for the SI 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.

Two channels of T_{avg} per loop are required to be OPERABLE. The T_{avg} channels are combined in a logic such that two channels tripped cause a trip for the parameter. The accidents that this Function protects against cause reduction of T_{avg} in the entire primary system. Therefore, the provision of two OPERABLE channels per loop in a

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

g. Steam Line Isolation—High Steam Flow Coincident With Safety Injection and Coincident With T_{avg}—Low Low (Two Loop Units) (continued)

two-out-of-four configuration ensures no single random failure disables the T_{avg}—Low Low Function. The T_{avg} channels provide control inputs, but the control function cannot initiate events that the Function acts to mitigate. Therefore, additional channels are not required to address control protection interaction issues.

With the T_{avg} resistance temperature detectors (RTDs) located inside the containment, it is possible for them to experience adverse environmental conditions during an SLB event. Therefore, the Trip Setpoint reflects both steady state and adverse environmental instrumental uncertainties.

This Function must be OPERABLE in MODES 1 and 2, and in MODE 3, when above the P-12 setpoint, when a secondary side break or stuck open valve could result in rapid depressurization of the steam lines. Below P-12 this Function is not required to be OPERABLE because the High High Steam Flow coincident with SI Function provides the required protection. The Steam Line Isolation Function is required to be OPERABLE in MODES 2 and 3 unless all MSIVs are closed and [de-activated]. This Function is not required to be OPERABLE in MODES 4, 5, and 6 because there is insufficient energy in the secondary side of the unit to have an accident.

h. Steam Line Isolation—High High Steam Flow Coincident With Safety Injection (Two Loop Units)

This Function provides closure of the MSIVs during a steam line break (or inadvertent opening of a relief or safety valve) to maintain at least one unfaulted SG as a heat sink for the reactor, and to limit the mass and energy release to containment.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

h. Steam Line Isolation—High High Steam Flow Coincident With Safety Injection (Two Loop Units) (continued)

Two steam line flow channels per steam line are required to be OPERABLE for this Function. These are combined in a one-out-of-two logic to indicate high steam flow in one steam line. The steam flow transmitters provide control inputs, but the control function cannot cause the events that the Function must protect against. Therefore, two channels are sufficient to satisfy redundancy requirements.

The Allowable Value for high steam flow is a ΔP, corresponding to 130% of full steam flow at full steam pressure. The Trip Setpoint is similarly calculated.

With the transmitters typically located inside the steam tunnels, it is possible for them to experience adverse environmental conditions during an SLB event. Therefore, the Trip Setpoint reflects both steady state and adverse environmental instrument uncertainties.

The main steam lines isolate only if the high steam flow signal occurs coincident with an SI signal. The Main Steam Line Isolation Function requirements for the SI 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.

This Function must be OPERABLE in MODES 1, 2, and 3 when a secondary side break or stuck open valve could result in rapid depressurization of the steam lines unless all MSIVs are closed and [de-activated]. This Function is not required to be OPERABLE in MODES 4, 5, and 6 because there is insufficient energy in the secondary side of the unit to have an accident.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

5. ~~Turbine Trip and~~ Feedwater Isolation

The ~~primary~~ function~~s~~ of the ~~Turbine Trip and~~ Feedwater Isolation signal~~s~~ ~~are~~ to ~~prevent damage to the turbine due to water in the steam lines, and to~~ stop the excessive flow of feedwater into the SGs. These Function~~s~~ ~~are~~ necessary to mitigate the effects of a high water level in the SGs, which could result in carryover of water into the steam lines and excessive cooldown of the primary system. The SG high water level is due to excessive feedwater flows.

~~The Function is actuated when the level in any SG exceeds the high high setpoint, and performs the following functions:~~

- ~~Trips the main turbine;~~
- ~~Trips the MFW pumps;~~
- ~~Initiates feedwater isolation; and~~
- ~~Shuts the MFW regulating valves and the bypass feedwater regulating valves.~~

This Function is actuated by ~~SG Water Level—High High, or by~~ an SI signal. The RTS also initiates a turbine trip signal whenever a reactor trip ~~(P-4)~~ is generated. In the event of SI, the unit is taken off line and the turbine generator must be tripped. The MFW System is also taken out of operation and the AFW System is automatically started. The SI signal was discussed previously.

~~a. Turbine Trip and Feedwater 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.~~

~~b. Turbine Trip and Feedwater Isolation—Steam Generator Water Level—High High (P-14)~~

~~This signal provides protection against excessive feedwater flow. The ESFAS SG water level~~

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. Turbine Trip and Feedwater Isolation—Steam Generator Water Level—High High (P-14) (continued)

instruments provide input to the SG Water Level Control System. Therefore, the actuation logic must be able to withstand both an input failure to the control system (which may then require the protection function actuation) and a single failure in the other channels providing the protection function actuation. Thus, four OPERABLE channels are required to satisfy the requirements with a two-out-of-four logic. For units that have dedicated protection and control channels, only three protection channels are necessary to satisfy the protective requirements. For other units that have only three channels, a median signal selector is provided or justification is provided in NUREG-1218 (Ref. 7).

The transmitters (d/p cells) are located inside containment. However, the events that this Function protects against cannot cause a severe environment in containment. Therefore, the Trip Setpoint reflects only steady state instrument uncertainties.

c. ~~Turbine Trip and~~ Feedwater Isolation—Safety Injection

Insert: B 3.3-92-01

~~Turbine Trip and~~ Feedwater Isolation is also initiated by all Functions that initiate SI. The Feedwater Isolation Function requirements for these 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.

~~Turbine Trip and~~ Feedwater Isolation Functions must be OPERABLE in MODES 1 and 2 ~~[~~and 3~~]~~ except when all MFIVs, MFRVs, ~~[~~and associated bypass valves~~]~~ are closed ~~and de-activated~~ ~~[~~or isolated by a closed manual valve~~]~~ when the MFW System is in operation ~~and the turbine generator may be in operation~~. In MODES ~~[2,]~~ 4, 5, and 6, the MFW System ~~and the turbine~~

low flow

(continued)

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Therefore, there are two trains of this Function, one initiated by SI train A and one initiated by SI train B.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

c. ~~Turbine Trip and~~ Feedwater Isolation—Safety Injection (continued)

~~generator are~~ 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, making it available during normal unit operation, during a loss of AC power, and a loss of MFW ~~, and during a Feedwater System pipe break~~. The normal source of water for the AFW System is the condensate storage tank (CST) ~~(normally not safety related)~~. ~~A low level in the CST will automatically realign the pump suctions to the Essential Service Water (ESW) System (safety related).~~ Additionally, City Water (CW) may be aligned to AFW to provide a backup water supply. 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 ~~(Solid State Protection System)~~

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—Automatic Actuation Logic and Actuation Relays (Balance of Plant ESFAS)~~

~~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. ~~c.~~ Auxiliary Feedwater—Steam Generator Water Level—Low Low

SG Water Level—Low Low provides protection against a loss of heat sink due to ~~A feed line break inside or outside of containment, or~~ a loss of MFW and the resulting ~~would result in a~~ loss of SG water level. ~~SG Water Level—Low Low provides input to the SG~~

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b ~~g.~~ Auxiliary Feedwater—Steam Generator Water Level—Low Low (continued)

Insert: B 3.3-94-01

~~Level Control System. Therefore, the actuation logic must be able to withstand both an input failure to the control system which may then require a protection function actuation and a single failure in the other channels providing the protection function actuation. Thus, four OPERABLE channels are required to satisfy the requirements with two-out-of-four logic. For units that have dedicated protection and control channels, only three protection channels are necessary to satisfy the protective requirements. For other units that have only three channels, a median signal selector is provided or justification is provided in Reference 7.~~

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

c ~~d.~~ Auxiliary Feedwater—Safety Injection

actuation

An SI signal starts the motor ~~driven and turbine~~ 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 ~~e.~~ Auxiliary Feedwater—Loss of Offsite Power

A turbine trip in conjunction with a (Non-SI blackout signal)

~~A~~ loss of offsite power to the service buses will be accompanied by a loss of reactor coolant pumping power and the subsequent need for some method of decay heat removal. The loss of offsite power is detected by a voltage drop on ~~each service bus~~. Loss of power to either ~~service~~ bus will start the turbine driven AFW pump~~s~~ to ensure that at least one SG contains enough water to serve as the heat sink for safeguards

480 V bus 3A and/or 6A

32

(continued)

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INSERT: B 3.3-94-01

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.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

d. Auxiliary Feedwater—Loss of Offsite Power (continued)

reactor decay heat and sensible heat removal following the reactor trip.

Insert: B3.3-95-01

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.

Operator action is required to initiate flow to an SG.

f. Auxiliary Feedwater—Undervoltage Reactor Coolant Pump

A loss of power on the buses that provide power to the RCPs provides indication of a pending loss of RCP forced flow in the RCS. The Undervoltage RCP Function senses the voltage downstream of each RCP breaker. A loss of power, or an open RCP breaker, on two or more RCPs, will start the turbine driven AFW pump to ensure that at least one SG contains enough water to serve as the heat sink for reactor decay heat and sensible heat removal following the reactor trip.

e. g. Auxiliary Feedwater—Trip of All Main Feedwater Pumps

either

potential

A Trip of all MFW pumps is an indication of a loss of MFW and the subsequent need for some method of decay heat and sensible heat removal to bring the reactor back to no load temperature and pressure. A turbine driven MFW pump is equipped with two pressure switches on the control oil

Each

(a)

(continued)

INSERT: B 3.3-95-01

following a loss of offsite power.

The LCO requires one Operable channel for bus 3A and one Operable channel for bus 6A. Either channel will start the turbine driven AFW pump. Therefore, a single failure of one channel of non-Safety Injection blackout sequence will not result in a loss of Function.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

g. Auxiliary Feedwater-Trip of ~~All~~ Main Feedwater Pumps (continued)

line for the speed control system. A low pressure signal from ~~either of these~~ this pressure switch~~es~~ indicates a trip of that pump. ~~Motor driven MFW pumps are equipped with a breaker position sensing device. An open supply breaker indicates that the pump is not running. Two OPERABLE channels per pump satisfy redundancy requirements with one-out-of-two taken twice logic.~~ A trip of ~~all~~ either MFW pumps starts ~~the~~ both motor ~~driven and turbine driven~~ AFW pumps to ensure that at least one SG is available with water to act as the heat sink for the reactor.

Insert: B33-96-01

Functions 6.~~f and 6.g~~ e must be OPERABLE in MODES 1 and 2. This ensures that at least one SG is provided with water to serve as the heat sink to remove reactor decay heat and sensible heat in the event of ~~an~~ loss of normal feedwater ~~accident~~. In MODES 3, 4, and 5, the ~~RCPs and MFW~~ MBF pumps ~~may be normally~~ are shut down, and thus ~~neither~~ does not require pump trip ~~is indicative of a condition requiring~~ automatic AFW initiation.

Indent

h. ~~Auxiliary Feedwater—Pump Suction Transfer on Suction Pressure—Low~~

~~A low pressure signal in the AFW pump suction line protects the AFW pumps against a loss of the normal supply of water for the pumps, the CST. Two pressure switches are located on the AFW pump suction line from the CST. A low pressure signal sensed by any one of the switches will cause the emergency supply of water for both pumps to be aligned, or cause the AFW pumps to stop until the emergency source of water is aligned. ESW (safety grade) is then lined up to supply the AFW pumps to ensure an adequate supply of water for the AFW System to maintain at least one of the SGs as the heat sink for reactor decay heat and sensible heat removal.~~

~~Since the detectors are located in an area not affected by HELBs or high radiation, they will not experience any adverse environmental~~

(continued)

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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 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 LCO requires one Operable channel for each operating MBFP.

BASES

APPLICABLE SAFETY ANALYSES LCO, and APPLICABILITY

h. Auxiliary Feedwater—Pump Suction Transfer on Suction Pressure—Low (continued)

conditions and the Trip Setpoint reflects only steady state instrument uncertainties.

This Function must be OPERABLE in MODES 1, 2, and 3 to ensure a safety grade supply of water for the AFW System to maintain the SGs as the heat sink for the reactor. This Function does 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 automatic suction transfer does not need to be OPERABLE because RHR will already be in operation, or sufficient time is available to place RHR in operation, to remove decay heat.

7. Automatic Switchover to Containment Sump

At the end of the injection phase of a LOCA, the RWST will be nearly empty. Continued cooling must be provided by the ECCS to remove decay heat. The source of water for the ECCS pumps is automatically switched to the containment recirculation sump. The low head residual heat removal (RHR) pumps and containment spray pumps draw the water from the containment recirculation sump, the RHR pumps pump the water through the RHR heat exchanger, inject the water back into the RCS, and supply the cooled water to the other ECCS pumps. Switchover from the RWST to the containment sump must occur before the RWST empties to prevent damage to the RHR pumps and a loss of core cooling capability. For similar reasons, switchover must not occur before there is sufficient water in the containment sump to support ESF pump suction. Furthermore, early switchover must not occur to ensure that sufficient borated water is injected from the RWST. This ensures the reactor remains shut down in the recirculation mode.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

a. Automatic Switchover to Containment Sump—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, c. Automatic Switchover to Containment Sump—Refueling Water Storage Tank (RWST) Level—Low Low Coincident With Safety Injection and Coincident With Containment Sump Level—High

During the injection phase of a LOCA, the RWST is the source of water for all ECCS pumps. A low low level in the RWST coincident with an SI signal provides protection against a loss of water for the ECCS pumps and indicates the end of the injection phase of the LOCA. The RWST is equipped with four level transmitters. These transmitters provide no control functions. Therefore, a two-out-of-four logic is adequate to initiate the protection function actuation. Although only three channels would be sufficient, a fourth channel has been added for increased reliability.

The RWST—Low Low Allowable Value/Trip Setpoint has both upper and lower limits. The lower limit is selected to ensure switchover occurs before the RWST empties, to prevent ECCS pump damage. The upper limit is selected to ensure enough borated water is injected to ensure the reactor remains shut down. The high limit also ensures adequate water inventory in the containment sump to provide ECCS pump suction.

The transmitters are located in an area not affected by HELBs or post accident high radiation. Thus, they will not experience any adverse environmental conditions and the Trip Setpoint reflects only steady state instrument uncertainties.

Automatic switchover occurs only if the RWST low low level signal is coincident with SI. This prevents accidental switchover during normal

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b, c. Automatic Switchover to Containment Sump—Refueling Water Storage Tank (RWST) Level—Low Low Coincident With Safety Injection and Coincident With Containment Sump Level—High (continued)

operation. Accidental switchover could damage ECCS pumps if they are attempting to take suction from an empty sump. The automatic switchover Function requirements for the SI 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.

Reviewer's Note: In some units, additional protection from spurious switchover is provided by requiring a Containment Sump Level—High signal as well as RWST Level—Low Low and SI. This ensures sufficient water is available in containment to support the recirculation phase of the accident. A Containment Sump Level—High signal must be present, in addition to the SI signal and the RWST Level—Low Low signal, to transfer the suctions of the RHR pumps to the containment sump. The containment sump is equipped with four level transmitters. These transmitters provide no control functions. Therefore, a two-out-of-four logic is adequate to initiate the protection function actuation. Although only three channels would be sufficient, a fourth channel has been added for increased reliability. The containment sump level Trip Setpoint/Allowable Value is selected to ensure enough borated water is injected to ensure the reactor remains shut down. The high limit also ensures adequate water inventory in the containment sump to provide ECCS pump suction. The transmitters are located inside containment and thus possibly experience adverse environmental conditions. Therefore, the trip setpoint reflects the inclusion of both steady state and environmental instrument uncertainties.

Units only have one of the Functions, 7.b or 7.c.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b, c. Automatic Switchover to Containment Sump—Refueling Water Storage Tank (RWST) Level—Low Low Coincident With Safety Injection and Coincident With Containment Sump Level—High (continued)

These Functions must be OPERABLE in MODES 1, 2, 3, and 4 when there is a potential for a LOCA to occur, to ensure a continued supply of water for the ECCS pumps. These Functions are not required to be OPERABLE in MODES 5 and 6 because there is adequate time for the operator to evaluate unit conditions and respond by manually starting systems, pumps, and other equipment to mitigate the consequences of an abnormal condition or accident. System pressure and temperature are very low and many ESF components are administratively locked out or otherwise prevented from actuating to prevent inadvertent overpressurization of unit systems.

8. Engineered Safety Feature Actuation System Interlocks

ESFAS Interlock - Pressurizer Pressure

To allow some flexibility in unit operations, several interlocks are included as part of the ESFAS. These interlocks permit the operator to block some signals, automatically enable other signals, prevent some actions from occurring, and cause other actions to occur. The interlock functions back up manual actions to ensure bypassable functions are in operation under the conditions assumed in the safety analyses.

Move to Page B 3.3-102

a. Engineered Safety Feature Actuation System Interlocks—Reactor Trip, P-4

The P-4 interlock is enabled when a reactor trip breaker (RTB) and its associated bypass breaker is open. Once the P-4 interlock is enabled, automatic SI initiation is blocked after a [ ] second time delay. This Function allows operators to take manual control of SI systems after the initial phase of injection is complete. Once SI is blocked, automatic actuation of SI cannot occur until the RTBs have been manually closed. The functions of the P-4 interlock are:

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

a. Engineered Safety Feature Actuation System Interlocks—Reactor Trip, P-4 (continued)

- Trip the main turbine;
- Isolate MFW with coincident low T_{avg};
- Prevent reactuation of SI after a manual reset of SI;
- Transfer the steam dump from the load rejection controller to the unit trip controller; and
- Prevent opening of the MFW isolation valves if they were closed on SI or SG Water Level—High High.

Each of the above Functions is interlocked with P-4 to avert or reduce the continued cooldown of the RCS following a reactor trip. An excessive cooldown of the RCS following a reactor trip could cause an insertion of positive reactivity with a subsequent increase in generated power. To avoid such a situation, the noted Functions have been interlocked with P-4 as part of the design of the unit control and protection system.

None of the noted Functions serves a mitigation function in the unit licensing basis safety analyses. Only the turbine trip Function is explicitly assumed since it is an immediate consequence of the reactor trip Function. Neither turbine trip, nor any of the other four Functions associated with the reactor trip signal, is required to show that the unit licensing basis safety analysis acceptance criteria are not exceeded.

The RTB position switches that provide input to the P-4 interlock only function to energize or de-energize or open or close contacts. Therefore, this Function has no adjustable trip setpoint with which to associate a Trip Setpoint and Allowable Value.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

a. Engineered Safety Feature Actuation System Interlocks—Reactor Trip, P-4 (continued)

This Function must be OPERABLE in MODES 1, 2, and 3 when the reactor may be critical or approaching criticality. This Function does not have to be OPERABLE in MODE 4, 5, or 6 because the main turbine, the MFW System, and the Steam Dump System are not in operation.

b. Engineered Safety Feature Actuation System Interlocks—Pressurizer Pressure, P-11

Pressurizer Pressure

The P-11 interlock permits a normal unit cooldown and depressurization without actuation of SI or main steam line isolation. With two-out-of-three pressurizer pressure channels (discussed previously) less than the P-11 setpoint, the operator can manually block the Pressurizer Pressure—Low and Steam Line Pressure—Low SI signals and the Steam Line Pressure—Low steam line isolation signal (previously discussed). When the Steam Line Pressure—Low steam line isolation signal is manually blocked, a main steam isolation signal on Steam Line Pressure—Negative Rate—High is enabled. This provides protection for an SLB by closure of the MSIVs. With two-out-of-three pressurizer pressure channels above the P-11 setpoint, the Pressurizer Pressure—Low and Steam Line Pressure—Low SI signals and the Steam Line Pressure—Low steam line isolation signal are automatically enabled. The operator can also enable these trips by use of the respective manual reset buttons. When the Steam Line Pressure—Low steam line isolation signal is enabled, the main steam isolation on Steam Line Pressure—Negative Rate—High is disabled. The Trip Setpoint reflects only steady state instrument uncertainties.

This Function must be OPERABLE in MODES 1, 2, and 3 to allow an orderly cooldown and depressurization of the unit without the actuation of SI or main steam isolation. This Function does not have to be OPERABLE in MODE 4,

Insert from Page B 3.3-100

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. Engineered Safety Feature Actuation System Interlocks—Pressurizer Pressure, P-11 (continued)

5, or 6 because system pressure must already be below the P-11 setpoint for the requirements of the heatup and cooldown curves to be met.

c. Engineered Safety Feature Actuation System Interlocks—T_{avg}—Low Low, P-12

On increasing reactor coolant temperature, the P-12 interlock reinstates SI on High Steam Flow Coincident With Steam Line Pressure—Low or Coincident With T_{avg}—Low Low and provides an arming signal to the Steam Dump System. On decreasing reactor coolant temperature, the P-12 interlock allows the operator to manually block SI on High Steam Flow Coincident With Steam Line Pressure—Low or Coincident with T_{avg}—Low Low. On a decreasing temperature, the P-12 interlock also removes the arming signal to the Steam Dump System to prevent an excessive cooldown of the RCS due to a malfunctioning Steam Dump System.

Since T_{avg} is used as an indication of bulk RCS temperature, this Function meets redundancy requirements with one OPERABLE channel in each loop. In three loop units, these channels are used in two-out-of-three logic. In four loop units, they are used in two-out-of-four logic.

This Function must be OPERABLE in MODES 1, 2, and 3 when a secondary side break or stuck open valve could result in the rapid depressurization of the steam lines. This Function does not have to be OPERABLE in MODE 4, 5, or 6 because there is insufficient energy in the secondary side of the unit to have an accident.

The ESFAS instrumentation satisfies Criterion 3 of the NRC Policy Statement.

10 CFR 50.36

(continued)

BASES (continued)

ACTIONS

Note!

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 3.3.2-1.

Insert: B3.3-104-01

In the event a channel's Trip Setpoint is found nonconservative with respect to the Allowable Value, or the transmitter, instrument Loop, signal processing electronics, or bistable is found inoperable, then all affected Functions provided by that channel must be declared inoperable and the LCO Condition(s) entered for the protection Function(s) affected. When the Required Channels in Table 3.3.2-1 are specified (e.g., on a per steam line, per loop, per SG, etc., basis), then the Condition may be entered separately for each steam line, loop, SG, etc., as appropriate.

When the number of inoperable channels in a trip function exceed those specified in one or other related Conditions associated with a trip function, then the unit is outside the safety analysis. Therefore, LCO 3.0.3 should be immediately entered if applicable in the current MODE of operation.

~~Reviewer's Note: Certain LCO Completion Times are based on approved topical reports. In order for a licensee to use these times, the licensee must justify the Completion Times as required by the staff Safety Evaluation Report (SER) for the topical report.~~

A.1

Condition A applies to all ESFAS protection functions.

Condition A addresses the situation where one or more channels or trains for one or more Functions are inoperable at the same time. The Required Action is to refer to Table 3.3.2-1 and to take the Required Actions for the protection functions affected. The Completion Times are those from the referenced Conditions and Required Actions.

(continued)

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Note 2 specifies that when a channel or train is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 8 hours, provided the associated Function(s) maintains ESFAS trip capability. Upon completion of the Surveillance, or expiration of the 8 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is consistent with the assumptions of the instrumentation system reliability analysis (Ref. 7). That analysis demonstrated that the 8 hour testing allowance does not significantly reduce the probability that the ESFAS will trip when necessary.

BASES

ACTIONS (continued)

B.1, B.2.1 and B.2.2

Condition B applies to manual initiation of:

- SI;
- Containment Spray;
- Phase A Isolation; and
- Phase B Isolation.

relay logic

This action addresses the train orientation of the SSPS for the functions listed above. If a channel or train is inoperable, 48 hours is allowed to return it to an OPERABLE status. Note that for containment spray and Phase B isolation, failure of one or both channels in one train renders the train inoperable. Condition B, therefore, encompasses both situations. The specified Completion Time is reasonable considering that there are two automatic actuation trains and another manual initiation train OPERABLE for each Function, and the low probability of an event occurring during this interval. If the train cannot be restored to OPERABLE status, the unit must be placed in a MODE in which the LCO does not apply. This is done by placing the unit in at least MODE 3 within an additional 6 hours (54 hours total time) and in MODE 5 within an additional 30 hours (84 hours total time). The allowable 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, C.2.1 and C.2.2

Condition C applies to the automatic actuation logic and actuation relays for the following functions:

- SI;
- Containment Spray;
- Phase A Isolation; and

(continued)

BASES

ACTIONS

C.1, C.2.1 and C.2.2 (continued)

- Phase B Isolation; and
- Automatic Switchover to Containment Sump.

relay logic

This action addresses the train orientation of the SSPS and the master and slave relays. If one train is inoperable, 6 hours are allowed to restore the train to OPERABLE status. The specified Completion Time is reasonable considering that there is another train OPERABLE, and the low probability of an event occurring during this interval. If the train cannot be restored to OPERABLE status, the unit must be placed in a MODE in which the LCO does not apply. This is done by placing the unit in at least MODE 3 within an additional 6 hours (12 hours total time) and in MODE 5 within an additional 30 hours (42 hours total time). The 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.

The Required Actions are 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 allowance is based on the reliability analysis assumption of WCAP-10271-P-A (Ref. 8) that 4 hours is the average time required to perform channel surveillance.

8 7 8

D.1, D.2.1, and D.2.2

Condition D applies to:

- Containment Pressure—High 3;
- Pressurizer Pressure—Low (two, three, and four loop units);
- Steam Line Pressure—Low;
- Steam Line Differential Pressure—High;
- High Steam Flow in Two Steam Lines Coincident With T_{avg}—Low Low or Coincident With Steam Line Pressure—Low;

High

Between Steam lines

(continued)

BASES

ACTIONS

D.1, D.2.1, and D.2.2 (continued)

- ~~Containment Pressure—High 2;~~
- ~~Steam Line Pressure—Negative Rate—High;~~
- ~~High Steam Flow Coincident With Safety Injection Coincident With T_{avg}—Low Low;~~
- ~~High High Steam Flow Coincident With Safety Injection;~~
- ~~High Steam Flow in Two Steam Lines Coincident With T_{avg}—Low Low;~~
- SG Water level—Low Low (~~two, three, and four loop~~ units)~~; and~~ .
- ~~SG Water level—High High (P-14) (two, three, and four loop units).~~

If one channel is inoperable, 6 hours are allowed to restore the channel to OPERABLE status or to place it in the tripped condition. Generally this Condition applies to functions that operate on two-out-of-three logic. Therefore, failure of one channel places the Function in a two-out-of-two configuration. One channel must be tripped to place the Function in a one-out-of-~~three~~ two configuration that satisfies redundancy requirements.

Insert: B 3.3-107-01

Failure to restore the inoperable channel to OPERABLE status or place it in the tripped condition within 6 hours requires the unit be placed in MODE 3 within the following 6 hours and MODE 4 within the next 6 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. In MODE 4, these Functions are no longer required OPERABLE.

8

The Required Actions are modified by a Note that allows the inoperable channel to be bypassed for up to [redacted] hours for surveillance testing of other channels. The 6 hours allowed to restore the channel to OPERABLE status or to place the inoperable channel in the tripped condition, and the 4 hours allowed for testing, are justified in Reference 8.

8

(continued)

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INSERT: B 3.3-107-01

Required Actions associated with High Steam Flow in Two Steam Lines Coincident With Tavg-Low or Coincident With Steam Line Pressure-Low are entered by treating Steam Flow, Tavg, and Steam Line Pressure as three separate Functions. The protective action is initiated on one-out-of-two high flow in any two-out-of-four steam lines if there is one-out-of-one low Tavg trip in any two-out-of-four RCS loops, or if there is a one-out-of-one low pressure trip in any two-out-of-four steam lines. This logic is acceptable because a single steam line fault will cause the remaining intact steam lines to pick up the full turbine load with the protective action initiated by the conditions in the no faulted steam lines. Therefore, a maximum of one channel of each of the three Functions may be placed in trip without creating a condition where a single failure will either cause or prevent the protective action.

BASES

ACTIONS (continued)

E.1, E.2.1, and E.2.2

Condition E applies to:

- Containment Spray Containment Pressure—~~High 3~~ (High, High) ~~(two, three, and four loop units)~~; and
- Containment Phase B Isolation Containment Pressure—~~High 3~~ (High, High).

• Steam Line Isolation Containment Pressure — (High High).

Insert B 3.3-108-01

~~None of these signals has input to a control function. Thus, two-out-of-three logic is necessary to meet acceptable protective requirements. However, a two-out-of-three design would require tripping a failed channel. This is undesirable because a single failure would then cause spurious containment spray initiation. Spurious spray actuation is undesirable because of the cleanup problems presented. Therefore, these channels are designed with two-out-of-four logic so that a failed channel may be bypassed rather than tripped. Note that one channel may be bypassed and still satisfy the single failure criterion. Furthermore, with one channel bypassed, a single instrumentation channel failure will not spuriously initiate containment spray.~~

Insert B 3.3-108-02

~~To avoid the inadvertent actuation of containment spray and Phase B containment isolation, the inoperable channel should not be placed in the tripped condition. Instead it is bypassed. Restoring the channel to OPERABLE status, or placing the inoperable channel in the bypass condition within 6 hours, is sufficient to assure that the Function remains OPERABLE and minimizes the time that the Function may be in a partial trip condition (assuming the inoperable channel has failed high). The Completion Time is further justified based on the low probability of an event occurring during this interval. Failure to restore the inoperable channel to OPERABLE status, or place it in the bypassed condition within 6 hours, requires the unit be placed in MODE 3 within the following 6 hours and MODE 4 within the next 6 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. In MODE 4, these Functions are no longer required OPERABLE.~~

(continued)

NUREG-1431 Markup Inserts
ITS SECTION 3.3.2 - ENGINEERED SAFETY FEATURE ACTUATION SYSTEM (ESFAS) INSTRUMENTATION

INSERT: B 3.3-108-01

The IP3 design for the Containment Pressure (High High) ESFAS Function consists of 2 sets of 3 channels. This design requires that 2 channels from each set of 3 are energizes to actuate the Containment Spray or Steam Line Isolation Functions. This configuration provides sufficient redundancy to prevent a single failure from causing or preventing containment spray initiation or steamline isolation even when testing with one inoperable channel per set already in trip.

Note that Condition E applies only when no more than one channel in one or both sets is inoperable. Otherwise, entry into LCO 3.0.3 is required. This is required because two inoperable channels from the same set that fail low could result in a loss of containment spray initiation or steamline isolation when a Containment Pressure (High High) ESFAS initiation is required. Additionally, this ensures that no more than one channel per set can be placed in trip which is required to decrease the probability of an inadvertent actuation of containment spray or steamline isolation if additional channels fail high.

INSERT: B 3.3-106-02

An inoperable channel is placed in trip within 6 hours to limit the amount of time that a single failure of a different channel on the same set could result in the failure of containment spray or steamline isolation to actuate. With no more than one channel from each set in trip, a single failure will not cause or prevent containment spray initiation or steamline isolation. Failure to place an inoperable channel in trip

BASES

ACTIONS

E.1, E.2.1, and E.2.2 (continued)

The Required Actions are modified by a Note that allows one additional channel to be bypassed for up to [4] hours for surveillance testing. Placing a second channel in the bypass condition for up to 4 hours for testing purposes is acceptable based on the results of Reference 8.

F.1, F.2.1, and F.2.2

Condition F applies to:

- Manual Initiation of Steam Line Isolation; and
- Loss of Offsite Power; (Non Safety Injection)
- ~~Auxiliary Feedwater Pump Suction Transfer on Suction Pressure—Low; and~~
- ~~P-4 Interlock.~~

Insert: B 3.3-109-01

~~For the Manual Initiation and the P-4 Interlock Functions, this action addresses the train orientation of the SSPS. For the Loss of Offsite Power Function, this action recognizes the lack of manual trip provision for a failed channel. For the AFW System pump suction transfer channels, this action recognizes that placing a failed channel in trip during operation is not necessarily a conservative action. Spurious trip of this function could align the AFW System to a source that is not immediately capable of supporting pump suction. If a train or channel is inoperable, 48 hours is allowed to return it to OPERABLE status. The specified Completion Time is reasonable considering the nature of these Functions, the available redundancy, and the low probability of an event occurring during this interval.~~ If either of these Functions cannot be returned to OPERABLE status, 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 experience, to reach the required unit conditions from full power in an orderly manner and without challenging unit systems. In MODE 4, the unit does not have any analyzed transients or conditions that require the explicit use of the protection functions noted above.

(continued)

INSERT: B 3.3-107-01

For the manual MSIV isolation Function, each MSIV will close if either of the two channels required per MSIV is tripped. If one channel is inoperable, the ability to tolerate a single failure is lost but manual isolation capability is maintained. Therefore, an inoperable channel cannot be placed in trip without causing an actuation and the inoperable channel must be restored to Operable to restore single failure protection. Additionally, since a single switch actuates both channels for each MSIV, the failure of a manual switch may result in the failure of both channels and a loss of Function. The specified Completion Time, 48 hours to restore an inoperable channel, is reasonable considering that there are two automatic actuation trains and another manual initiation train OPERABLE for each MSIV, and the low probability of an event occurring during this interval. Each MSIV is considered a separate Function.

For the Loss of Offsite Power (Non-Safety Injection) Function, either channel (bus 3A or bus 6A) will start the turbine driven AFW pump. If one channel is inoperable, the AFW starting Function for the turbine driven AFW pump on loss of offsite power is maintained by the channel associated with the other bus. Two inoperable channels result in a loss of this Function; therefore, entry into LCO 3.0.3 is requried.

For the Loss of Offsite Power (Non-Safety Injection) Function, an inoperable channel cannot be placed in trip without causing an actuation: therefore, an inoperable channel must be restored to Operable. The specified Completion Time, 48 hours to restore an inoperable channel, is reasonable considering that this is a Non-Safety Injection start of the AFW, the availability of manual starting capability, and the low probability of an event occurring during this interval. Additionally, other Functions, in particular SG Water Level – Low Low, provide the primary protection against a loss of heat sink.

BASES

ACTIONS (continued)

G.1, G.2.1 and G.2.2

Condition G applies to the automatic actuation logic and actuation relays for the Steam Line Isolation ~~, Turbine Trip and Feedwater Isolation,~~ and AFW actuation Functions.

Relay logic

The action addresses the train orientation of the SSPS and the ~~master and slave~~ relays for these functions. If one train is inoperable, 6 hours are allowed to restore the train to OPERABLE status. The Completion Time for restoring a train to OPERABLE status is reasonable considering that there is another train OPERABLE, and the low probability of an event occurring during this interval. If the train cannot be returned to OPERABLE status, the unit must be brought to MODE 3 within the next 6 hours and MODE 4 within the following 6 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. Placing the unit in MODE 4 removes all requirements for OPERABILITY of the protection channels and actuation functions. In this MODE, the unit does not have analyzed transients or conditions that require the explicit use of the protection functions noted above.

actuation

Insert: B 3.3-110-01

The Required Actions are 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 allowance is based on the reliability analysis (Ref. 8) assumption that 4 hours is the average time required to perform channel surveillance.

8 7 8

H.1 and H.2

Condition H applies to the automatic actuation logic and actuation relays for the ~~Turbine Trip and~~ Feedwater Isolation Function.

relay logic

This action addresses the train orientation of the SSPS and the ~~master and slave~~ relays for this Function. If one train is inoperable, 6 hours are allowed to restore the train to OPERABLE status or the unit must be placed in MODE 3 within the following 6 hours. The Completion Time for restoring a train to OPERABLE status is reasonable considering that there is another train OPERABLE, and the low probability of

actuation

Insert: B 3.3-110-02

(continued)

NUREG-1431 Markup Inserts
ITS SECTION 3.3.2 - ENGINEERED SAFETY FEATURE ACTUATION SYSTEM (ESFAS) INSTRUMENTATION

INSERT: B 3.3-110-01

unless the plant can be placed outside of the Applicable MODE or Conditions by other means (e.g., shutting all MSIVs).

INSERT: B 3.3-110-02

unless the plant can be placed outside of the Applicable MODE or Conditions by other means (e.g., shutting all MBFPDVs or MBFRVs and associated bypass valves).

BASES

ACTIONS

H.1 and H.2 (continued)

an event occurring during this interval. 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 unit systems. These Functions are no longer required in MODE 3. Placing the unit in MODE 3 removes all requirements for OPERABILITY of the protection channels and actuation functions. In this MODE, the unit does not have analyzed transients or conditions that require the explicit use of the protection functions noted above.

The Required Actions are 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 allowance is based on the reliability analysis (Ref. 8) assumption that 4 hours is the average time required to perform channel surveillance.

I.1 and I.2

Condition I applies to:

- SG Water Level—High High (P-14) (two, three, and four loop units); and
- Undervoltage Reactor Coolant Pump.

If one channel is inoperable, 6 hours are allowed to restore one channel to OPERABLE status or to place it in the tripped condition. If placed in the tripped condition, the Function is then in a partial trip condition where one-out-of-two or one-out-of-three logic will result in actuation. The 6 hour Completion Time is justified in Reference 8. Failure to restore the inoperable channel to OPERABLE status or place it in the tripped condition within 6 hours requires the unit to be placed in MODE 3 within the following 6 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 unit systems. In MODE 3, these Functions are no longer required OPERABLE.

(continued)

BASES

ACTIONS

I.1 and I.2 (continued)

The Required Actions are modified by a Note that allows the inoperable channel to be bypassed for up to [4] hours for surveillance testing of other channels. The 6 hours allowed to place the inoperable channel in the tripped condition, and the 4 hours allowed for a second channel to be in the bypassed condition for testing, are justified in Reference 8.

I.1. , I.2. and J.1

J.1 and J.2

Main Boiler Feedwater

either

Condition J applies to the AFW pump start on trip of all MFW pumps.

Insert B 3.3.112-01

This action addresses the train orientation of the SSPS for the auto start function of the AFW System on loss of all MFW pumps. The OPERABILITY of the AFW System must be assured by allowing automatic start of the AFW System pumps. If a channel is inoperable, 48 hours are allowed to return it to an OPERABLE status. If the function cannot be returned to an OPERABLE status, 6 hours are allowed to place the unit in MODE 3. 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 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. The allowance of 48 hours to return the train to an OPERABLE status is justified in Reference 8.

by Required Action J.1

K.1, K.2.1 and K.2.2

Condition K applies to:

- RWST Level—Low Low Coincident with Safety Injection; and
- RWST Level—Low Low Coincident with Safety Injection and Coincident with Containment Sump Level—High.

RWST Level—Low Low Coincident With SI and Coincident With Containment Sump Level—High provides actuation of switchover to the containment sump. Note that this Function

(continued)

INSERT: B 3.3-112-01

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. Therefore, when a channel is inoperable, Required Action I.1.1, verifies that one channel associated with an operating MBFP is OPERABLE to ensure that there is no loss of function. Otherwise, entry into LCO 3.0.3 is required. If both MBFPs are operating, Required Action I.2.1 allows 48 hours to restore redundancy by requiring one channel associated with each operating MBFP to be OPERABLE. Continued operating without redundant channels when only one 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.

BASES

ACTIONS

K.1, K.2.1 and K.2.2 (continued)

requires the bistables to energize to perform their required action. The failure of up to two channels will not prevent the operation of this Function. However, placing a failed channel in the tripped condition could result in a premature switchover to the sump, prior to the injection of the minimum volume from the RWST. Placing the inoperable channel in bypass results in a two-out-of-three logic configuration, which satisfies the requirement to allow another failure without disabling actuation of the switchover when required. Restoring the channel to OPERABLE status or placing the inoperable channel in the bypass condition within 6 hours is sufficient to ensure that the Function remains OPERABLE, and minimizes the time that the Function may be in a partial trip condition (assuming the inoperable channel has failed high). The 6 hour Completion Time is justified in Reference 8. If the channel cannot be returned to OPERABLE status or placed in the bypass condition within 6 hours, the unit must be brought to MODE 3 within the following 6 hours and MODE 5 within the next 30 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. In MODE 5, the unit does not have any analyzed transients or conditions that require the explicit use of the protection functions noted above.

The Required Actions are modified by a Note that allows placing a second channel in the bypass condition for up to [4] hours for surveillance testing. The total of 12 hours to reach MODE 3 and 4 hours for a second channel to be bypassed is acceptable based on the results of Reference 8.

K

L.1, L.2.1 and L.2.2 K

Pressurizer Pressure

Condition L applies to the ~~P-11 and P-12 [and P-14]~~ interlock~~s~~.

one or more Channels

With ~~one channel~~ 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

(continued)

BASES

ACTIONS (J) D.1, D.2.1 and D.2.2 (continued)

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 experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. Placing the unit in MODE 4 removes all requirements for OPERABILITY of ~~these~~ Thus interlock~~s~~.

SURVEILLANCE REQUIREMENTS

The SRs for each ESFAS Function are identified by the SRs column of Table 3.3.2-1.

A Note has been added to the SR Table to clarify that Table 3.3.2-1 determines which SRs apply to which ESFAS Functions.

Insert: B 3.3-114-01

Note that each channel of process protection supplies both trains of the ESFAS. ~~When testing channel I, train A and train B must be examined. Similarly, train A and train B must be examined when testing channel II, channel III, and channel IV (if applicable).~~ The CHANNEL CALIBRATION and COTs are performed in a manner that is consistent with the assumptions used in ~~analytically calculating the required channel accuracies.~~

the setpoint methodology described in Reference 6.

~~Reviewer's Note: Certain Frequencies are based on approved topical reports. In order for a licensee to use these times, the licensee must justify the Frequencies as required by the staff SER for the topical report.~~

SR 3.3.2.1

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

(continued)

BASES

ACTIONS

SR 3.3.2.1 (continued)

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.

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including indication and reliability. 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 3.3.2.2

required in Table 3.3.2-1

relay logic

SR 3.3.2.2 is the performance of an ACTUATION LOGIC TEST. The ~~SSPS~~ is tested every 31 days on a STAGGERED TEST BASIS. ~~using the semiautomatic tester~~. The train being tested is placed in the bypass condition, thus preventing inadvertent actuation. ~~Through the semiautomatic tester~~ All possible logic combinations, ~~with and without applicable permissives,~~ are tested for each protection function. In addition, the master relay ~~coil~~ is ~~pulse~~ tested. ~~for continuity~~. This verifies that the logic modules are OPERABLE and that there is ~~an intact~~ voltage signal path to the master relay coils. The Frequency of every 31 days on a STAGGERED TEST BASIS is adequate. It is based on industry operating experience, considering instrument reliability and operating history data.

a

SR 3.3.2.3

~~SR 3.3.2.3 is the performance of an ACTUATION LOGIC TEST as described in SR 3.3.2.2, except that the semiautomatic~~

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.3 (continued)

tester is not used and the continuity check does not have to be performed, as explained in the Note. This SR is applied to the balance of plant actuation logic and relays that do not have the SSPS test circuits installed to utilize the semiautomatic tester or perform the continuity check. This test is also performed every 31 days on a STAGGERED TEST BASIS. The Frequency is adequate based on industry operating experience, considering instrument reliability and operating history data.

SR 3.3.2.~~4~~ 3

SR 3.3.2.~~4~~ 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 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 time allowed for the testing (~~4~~ hours) and the surveillance interval are justified in Reference ~~8~~. 7

supplied

8

SR 3.3.2.~~5~~ 4

SR 3.3.2.~~5~~ is the performance of a COT.

(with the exception of the transmitter sensing devices)

A COT is performed on each required channel to ensure the entire channel will perform the intended Function. Setpoints must be found within the ~~Allowable Values~~ ~~specified in Table 3.3.1-1~~

calibration acceptance criteria

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.

(Ref. 6)

The "as found" and "as left" values must also be recorded and reviewed. ~~for consistency with the assumptions of the~~

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.~~8~~ 4 (continued)

~~surveillance interval extension analysis (Ref. 8) when applicable.~~

The Frequency of 92 days is justified in Reference ~~8~~ 7.

SR 3.3.2.~~6~~ 5

SR 3.3.2.~~6~~ 5 is the performance of a SLAVE RELAY TEST. The SLAVE RELAY TEST is the energizing of the slave relays. Contact operation is verified in one of two ways. Actuation equipment that may be operated in the design mitigation MODE is either allowed to function, or is placed in a condition where the ~~relay contact~~ circuit operation can be verified without operation of the equipment. Actuation equipment that may not be operated in the design mitigation MODE is prevented from operation ~~by the SLAVE RELAY TEST circuit~~. ~~For this~~ Alternately ~~latter case~~, contact operation ~~is~~ may be verified by a continuity check of the circuit containing the slave relay. This test is performed every ~~[92] days~~ 24 months. The Frequency is adequate, based on ~~industry~~ operating experience, considering instrument reliability and operating history data.

SR 3.3.2.7

SR 3.3.2.7 is the performance of a TADOT every [92] days. This test is a check of the Loss of Offsite Power, Undervoltage RCP, and AFW Pump Suction Transfer on Suction Pressure—Low Functions. Each Function is tested up to, and including, the master transfer relay coils.

The test also includes trip devices that provide actuation signals directly to the SSPS. The SR is modified by a Note that excludes verification of setpoints for relays. Relay setpoints require elaborate bench calibration and are verified during CHANNEL CALIBRATION. The Frequency is adequate. It is based on industry operating experience, considering instrument reliability and operating history data.

(continued)

BASES

or loss of offsite power (non SI)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.~~8~~ 6

SR 3.3.2.~~8~~ is the performance of a TADOT. This test is a check of the Manual Actuation Functions and AFW pump start on trip of ~~a~~ either MFW pump~~s~~. It is performed every [18] 24 months. Each Manual Actuation Function is tested up to, and including, the master relay coils. In some instances, the test includes actuation of the end device (i.e., pump starts, valve cycles, etc.). The Frequency is adequate, based on industry operating experience and is consistent with the typical refueling cycle. The SR is modified by a Note that excludes verification of setpoints during the TADOT for manual initiation Functions. The manual initiation Functions have no associated setpoints.

SR 3.3.2.~~9~~ 7

SR 3.3.2.~~9~~ is the performance of a CHANNEL CALIBRATION.

A CHANNEL CALIBRATION is performed every [18] 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 measured parameter within the necessary range and accuracy.

CHANNEL CALIBRATIONS must be performed consistent with the assumptions of the unit specific setpoint methodology (Ref. 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 [18] 24 months is based on the assumption of an [18] 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint methodology.

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

~~SR 3.3.2.10~~

~~This SR ensures the individual channel ESF RESPONSE TIMES are less than or equal to the maximum values assumed in the~~

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.10 (continued)

accident analysis. Response Time testing acceptance criteria are included in the Technical Requirements Manual, Section 15 (Ref. 9). Individual component response times are not modeled in the analyses. The analyses model the overall or total elapsed time, from the point at which the parameter exceeds the Trip Setpoint value at the sensor, to the point at which the equipment in both trains reaches the required functional state (e.g., pumps at rated discharge pressure, valves in full open or closed position).

For channels that include dynamic transfer functions (e.g., lag, lead/lag, rate/lag, etc.), the response time test may be performed with the transfer functions set to one with the resulting measured response time compared to the appropriate FSAR response time. Alternately, the response time test can be performed with the time constants set to their nominal value provided the required response time is analytically calculated assuming the time constants are set at their nominal values. The response time may be measured by a series of overlapping tests such that the entire response time is measured.

ESF RESPONSE TIME tests are conducted on an [18] month STAGGERED TEST BASIS. Testing of the final actuation devices, which make up the bulk of the response time, is included in the testing of each channel. The final actuation device in one train is tested with each channel. Therefore, staggered testing results in response time verification of these devices every [18] months. The [18] month Frequency is consistent with the typical refueling cycle and is based on unit operating experience, which shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent occurrences.

This SR is modified by a Note that clarifies that the turbine driven AFW pump is tested within 24 hours after reaching [1000] psig in the SGs.

SR 3.3.2.11

SR 3.3.2.11 is the performance of a TADOT as described in SR 3.3.2.8, except that it is performed for the P-4 Reactor

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.11 (continued)

Trip Interlock, and the Frequency is once per RTB cycle. This Frequency is based on operating experience demonstrating that undetected failure of the P-4 interlock sometimes occurs when the RTB is cycled.

The SR is modified by a Note that excludes verification of setpoints during the TADOT. The Function tested has no associated setpoint.

REFERENCES

1. FSAR, Chapter [6].
2. FSAR, Chapter [7].
3. FSAR, Chapter [15]. 14
4. IEEE-279-1971. 1968
5. 10 CFR 50.49.
6. RTS/ESFAS Setpoint Methodology Study
7. NUREG-1218, April 1988.
7 8. WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.
9. Technical Requirements Manual, Section 15, "Response Times."

Insert: B 3.3-120-01

Insert B 3.3-120-02

NUREG-1431 Markup Inserts
ITS SECTION 3.3.2 - ENGINEERED SAFETY FEATURE ACTUATION SYSTEM (ESFAS) INSTRUMENTATION

INSERT B 3.3-120-01:

6. Engineering Standards Manual IES-3B and IES-3, Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3).

INSERT B 3.3-120-02:

8. Consolidated Edison Company of New York, Inc. Indian Point Nuclear Generating Station Unit No. 3 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, March 1975.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.2:

"Engineered Safety Feature Actuation System (ESFAS) Instrumentation"

PART 6:

Justification of Differences between

NUREG-1431 and IP3 ITS

JUSTIFICATION OF DIFFERENCES FROM NUREG-1431
ITS SECTION 3.3.2 - ENGINEERED SAFETY FEATURE ACTUATION SYSTEM
(ESFAS) INSTRUMENTATION

RETENTION OF EXISTING REQUIREMENT (CURRENT LICENSING BASIS)

CLB.1 NUREG-1431, Rev 1, Section 3.3.2, was modified as needed to reflect the IP3 design and current licensing basis. A detailed description of the design, accident analysis assumptions, and Operability requirements are incorporated into the IP3 ITS Bases. These changes maintain the IP3 current licensing basis except as identified and justified in the CTS/ITS discussion of changes.

PLANT-SPECIFIC WORDING PREFERENCE OR MINOR EDITORIAL IMPROVEMENT

PA.1 Corrected typographical error or made a minor editorial improvement to improve clarity and ensure requirements are fully understood and consistently applied. There are no technical changes to requirements as specified in NUREG 1431, Rev. 1; therefore, this change is not a significant or generic deviation from NUREG 1431, Rev 1.

PLANT-SPECIFIC DIFFERENCE IN THE DESIGN OR DESIGN BASIS

DB.1 Design or implementation details are incorporated or revised as necessary to more precisely describe IP3 current design or practice. These changes are intended to describe the design, improve clarity, or ensure requirements are fully understood and consistently applied. Unless identified and described blow, these changes are self-explanatory. A detailed description of the design, accident analysis assumptions, and Operability requirements are incorporated into the IP3 ITS Bases. These changes maintain the IP3 current licensing basis except as identified and justified in the CTS/ITS discussion of changes.

DIFFERENCE BASED ON A GENERIC CHANGE TRAVELER FOR NUREG-1431

T.1 This change incorporates Revision 2 of Generic Change TSTF-135 (WOG-58) which incorporates several corrections and clarifications to Required Actions for this Limiting condition for Operation.

JUSTIFICATION OF DIFFERENCES FROM NUREG-1431
ITS SECTION 3.3.2 - ENGINEERED SAFETY FEATURE ACTUATION SYSTEM
(ESFAS) INSTRUMENTATION

DIFFERENCE FOR ANY REASON OTHER THAN ABOVE

None

Indian Point 3

Improved

Technical Specifications

Conversion Submittal

Volume 6

New York Power Authority

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.3:
"Post Accident Monitoring (PAM) Instrumentation"

PART 1:

Indian Point 3
Improved Technical Specifications and Bases

3.3 INSTRUMENTATION

3.3.3 Post Accident Monitoring (PAM) Instrumentation

LCO 3.3.3 The PAM instrumentation for each Function in Table 3.3.3-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

----------NOTES----------

1. LCO 3.0.4 is not applicable.

2. Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more Functions with one required channels inoperable.	A.1	Restore one channel to OPERABLE status.	7 days
B. Required Action and associated Completion Time of Condition A not met. <u>OR</u> One or more Functions with two required channels inoperable.	B.1	Enter the Condition referenced in Table 3.3.3-1 for the channel.	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. As required by Required Action B.1 and referenced in Table 3.3.3-1.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	6 hours 12 hours
D. As required by Required Action B.1 and referenced in Table 3.3.3-1.	D.1 Initiate action in accordance with Specification 5.6.7.	Immediately

SURVEILLANCE REQUIREMENTS

----------NOTE----------
SR 3.3.3.1 and SR 3.3.3.2 apply to each PAM instrumentation Function in Table 3.3.3-1.

SURVEILLANCE		FREQUENCY
SR 3.3.3.1	Perform CHANNEL CHECK for each required instrumentation channel that is normally energized.	31 days
SR 3.3.3.2	----------NOTE---------- Neutron detectors are excluded from CHANNEL CALIBRATION. ---------- Perform CHANNEL CALIBRATION.	As specified in Table 3.3.3-1

Table 3.3.3-1 (page 1 of 1)
Post Accident Monitoring Instrumentation

	FUNCTION	REQUIRED CHANNELS	CONDITION REFERENCED FROM REQUIRED ACTION B.1	SR 3.3.3.2 FREQUENCY
1.	Neutron Flux	1	D	24 months
2.	RCS Hot Leg Temperature (wide range)	1 loop	C	24 months
3.	RCS Cold Leg Temperature (wide range)	1 loop	C	24 months
4.	RCS Pressure (wide Range)	1	C	24 months
5.	Reactor Vessel Water Level	1	C	24 months
6.	Containment Water Level (Wide Range)	1	C	24 months
7.	Containment Water Level (Recirculation Sump)	1	C	24 months
8.	Containment Pressure	1	C	18 months
9.	Automatic Containment Isolation Valve Position	per penetration flow path(a)	D	24 months
10.	Containment Area Radiation (High Range)	1	D	24 months
11.	Containment Hydrogen Monitors	1(c)	C	92 days
12.	Pressurizer Level	2	C	24 months
13.	SG Water Level (Narrow Range)	2 (b)	C	24 months
14.	SG Water Level (Wide Range)	2 (b)	C	24 months
15.	Steam Generator Pressure	1 per steam generator	C	24 months
16.	Condensate Storage Tank Level	1	D	24 months
17.	RWST Level, Alarm	2	C	(d)
18.	Core Exit Thermocouples-Quadrant 1	2	C	24 months
19.	Core Exit Thermocouples-Quadrant 2	2	C	24 months
20.	Core Exit Thermocouples-Quadrant 3	2	C	24 months
21.	Core Exit Thermocouples-Quadrant 4	2	C	24 months
22.	Main Steam Line Radiation	1 per steam line	D	24 months
23.	Gross Failed Fuel Detector	1	D	24 months
24.	RCS Subcooling Margin	1	C	24 months

(a) Not required for isolation valves whose associated penetration is isolated by at least one closed and deactivated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured.

(b) Two of the four steam generators must have one OPERABLE wide range level channel and the remaining two steam generators must each have one OPERABLE level channel which may be either wide range or narrow range.

(c) Hydrogen monitor OPERABILITY requires that the associated containment fan cooler unit is OPERABLE.

(d) 18 months for RWST level alarm transmitters and 6 months for RWST alarm switches.

B 3.3 INSTRUMENTATION

B 3.3.3 Post Accident Monitoring (PAM) Instrumentation

BASES

BACKGROUND

The primary purpose of the PAM instrumentation is to display unit variables that provide information required by the control room operators during accident situations. This information provides the necessary support for the operator to take the manual actions for which no automatic control is provided and that are required for safety systems to accomplish their safety functions for Design Basis Accidents (DBAs).

The OPERABILITY of the accident monitoring instrumentation ensures that there is sufficient information available on selected unit parameters to monitor and to assess unit status and behavior following an accident.

The availability of accident monitoring instrumentation is important so that responses to corrective actions can be observed and the need for, and magnitude of, further actions can be determined. These essential instruments are identified by unit specific documents (Ref. 1) addressing the recommendations of Regulatory Guide 1.97 (Ref. 2) as required by Supplement 1 to NUREG-0737 (Ref. 3).

The instrument channels required to be OPERABLE by this LCO include two classes of parameters identified during unit specific implementation of Regulatory Guide 1.97. The instruments governed by this LCO are the Type A and Category I variables which are defined as follows:

Type A variables are included in this LCO because they provide the primary information required for the control room operator to take specific manually controlled actions for which no automatic control is provided, and that are required for safety systems to accomplish their safety functions for DBAs.

BASES

BACKGROUND (continued)

Category I variables are the key variables deemed risk significant because they are needed to:

- Determine whether other systems important to safety are performing their intended functions;
- Provide information to the operators that will enable them to determine the likelihood of a gross breach of the barriers to radioactivity release; and
- Provide information regarding the release of radioactive materials to allow for early indication of the need to initiate action necessary to protect the public, and to estimate the magnitude of any impending threat.

These key variables are identified by the unit specific Regulatory Guide 1.97 analyses (Ref. 1). These analyses identify the unit specific Type A and Category I variables and provide justification for deviating from the NRC proposed list of Category I variables.

The specific instrument Functions listed in Table 3.3.3-1 are discussed in the LCO section.

APPLICABLE SAFETY ANALYSES

The PAM instrumentation ensures the operability of Regulatory Guide 1.97 Type A and Category I variables so that the control room operating staff can:

- Perform the diagnosis specified in the emergency operating procedures (these variables are restricted to preplanned actions for the primary success path of DBAs), e.g., loss of coolant accident (LOCA);
- Take the specified, pre-planned, manually controlled actions, for which no automatic control is provided, and that are required for safety systems to accomplish their safety function;

BASES

APPLICABLE SAFETY ANALYSES (continued)

- Determine whether systems important to safety are performing their intended functions;
- Determine the likelihood of a gross breach of the barriers to radioactivity release;
- Determine if a gross breach of a barrier has occurred; and
- Initiate action necessary to protect the public and to estimate the magnitude of any impending threat.

PAM instrumentation that meets the definition of Type A in Regulatory Guide 1.97 satisfies Criterion 3 of 10 CFR 50.36. 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 and therefore, meet Criterion 4 of 10 CFR 50.36.

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 provides information about selected unit parameters to monitor and assess unit status following an accident. This capability is consistent with the recommendations of Reference 1. This LCO requires OPERABILITY of only one channel of each Type A and Category I variable. The additional channels of each Type A and Category I instrument described in Reference 1 and needed to meet Reference 2 requirements for single failure tolerance and channel diversity are controlled administratively.

BASES

LCO (continued)

Table 3.3.3-1 provides a list of all Type A and Category I variables identified by the IP3 Regulatory Guide 1.97 analyses, as amended by the NRC's SER Reference 1.

Type A and Category I variables are required to meet Regulatory Guide 1.97 Category I (Ref. 2) design and qualification requirements for seismic and environmental qualification, utilization of emergency standby power, immediately accessible display, continuous readout, and recording of display.

Requirements for single failure tolerance and channel diversity are controlled administratively.

The Safety Parameter Display System (SPDS) is provided to the Control Room to continuously displays information from which plant status can be assessed. The SPDS consists of the Critical Functions Monitoring System (CFMS) and the Qualified Safety Parameters Display System (QSPDS). The CFMS displays and alarms critical safety functions (actions which preserve integrity of one or more physical barriers against radiation) in the Control Room and the emergency response facilities. The CFMS is a redundant computer system not designed to seismic and electrical class 1E criteria. The QSPDS is qualified to seismic and electrical class 1E standards (Ref. 4). Note that the Qualified Safety Parameter Display System (QSPDS) is fully qualified to display and record Category 1 instrumentation as recommended by Regulatory Guide 1.97, Rev. 3 (Ref. 1).

Listed below are discussions of the specified instrument Functions listed in Table 3.3.3-1.

1. Neutron Flux

Neutron Flux indication covering full range of flux that may occur post accident is provided to verify reactor shutdown. Neutron flux is used for accident diagnosis, verification of subcriticality, and diagnosis of positive reactivity insertion.

BASES

LCO (continued)

To satisfy these requirements, an Excore Neutron Flux Detection System consisting of two detectors (N38, N39) provides two channels of neutron flux indication capable of providing indication from the source range to 100% RTP. Either one of these channels is required to be OPERABLE to satify requirements of this LCO. The Excore Neutron Flux Detection System is an indication only system that displays on the QSPDS in the Control Room. Redundancy for this function is provided by the source range, intermediate range and power range instruments of the Nuclear Instrumentation System.

2, 3. Reactor Coolant System (RCS) Hot and Cold Leg Temperatures (Wide Range)

RCS Hot and Cold Leg Temperatures are Category I variables required for verification of core cooling and long term surveillance. RCS cold leg temperature is used in conjunction with RCS hot leg temperature and steam gnerator pressure to verify the unit conditions necessary to establish natural circulation in the RCS.

This LCO is satisfied by the OPERABILITY of any one hot leg instrument and any one cold leg instrument from the following list:

Hot Leg Loop No. 1 (T413A)	Cold Leg Loop No. 1 (T413B)
Hot Leg Loop No. 2 (T423A)	Cold Leg Loop No. 2 (T423B)
Hot Leg Loop No. 3 (T433A)	Cold Leg Loop No. 3 (T433B)
Hot Leg Loop No. 4 (T443A)	Cold Leg Loop No. 4 (T443B)

Redundancy for the Hot Leg RCS Temperature is provided by the core exit thermocouples (Functions 18, 19, 20 and 21) which is considered a diverse variable for the RCS Hot Leg indication. Redundancy for the Cold Leg RCS Temperature is provided by Steam Generator Pressure (Function 15).

4. Reactor Coolant System Pressure (Wide Range)

RCS wide range pressure is a Category I variable required for verification of core cooling and RCS integrity long term surveillance.

BASES

LCO (continued)

RCS pressure is used to verify closure of manually closed pressurizer spray line valves and pressurizer power operated relief valves (PORVs). In addition, RCS pressure is used for determining RCS subcooling margin. RCS subcooling margin will allow termination of SI, if still in progress, or reinitiation of SI if it has been stopped. RCS pressure can also be used:

- to determine whether to terminate actuated SI or to reinitiate stopped SI;
- to determine when to reset SI and shut off low head SI;
- to manually restart low head SI;
- as reactor coolant pump (RCP) trip criteria; and
- to make a determination on the nature of the accident in progress and where to go next in the procedure.

RCS subcooling margin is also used for unit stabilization and cooldown control.

RCS pressure is also related to three decisions about depressurization. They are:

- to determine whether to proceed with primary system depressurization;
- to verify termination of depressurization; and
- to determine whether to close accumulator isolation valves during a controlled cooldown/depressurization.

RCS pressure is also used to determine whether to operate the pressurizer heaters.

RCS pressure is a Type A variable because the operator uses this indication to monitor the depressurization of the RCS following a steam generator tube rupture (SGTR) or small break LOCA. Operator actions to maintain a controlled cooldown, such as adjusting steam generator (SG) pressure or level, would use this

BASES

LCO (continued)

indication. Furthermore, RCS pressure is one factor that may be used in decisions to terminate RCP operation.

The LCO requirement for 1 channel of RCS Pressure (wide range) indication is satisfied by either pressure transmitter designated PT-402 or PT-403. Normal control room indication or recorders or displays on the QSPDS in the Control Room will satisfy this requirement.

Redundancy for RCS Pressure (wide range) indication is provided by the RCS 0-3000 psig pressure gauge which is located in an area accessible to plant operators. Additionally, pressure transmitters used to monitor pressurizer pressure (PT-455, PT-456, PT-457 and PT-474) for the range of 1700-2500 psig are available.

5. Reactor Vessel Water Level

Reactor Vessel Water Level is required for verification and long term surveillance of core cooling. It is also used for accident diagnosis and to determine reactor coolant inventory adequacy.

This requirement is satisfied by either of the two channels of the Reactor Vessel Level Indicating System (RVLIS). The RVLIS automatically compensate for variations in fluid density as well as for the effects of reactor coolant pump operation. The collapsed level represents the amount of liquid mass that is in the reactor vessel. Measurement of the collapsed water level is selected because it is a direct indication of the water inventory. The level instrumentation is divided into the full range and the dynamic range in order to measure level under all conditions. The full range gives level indication from the bottom of the reactor vessel to the top of the reactor head during natural circulation conditions. The dynamic range gives indication of reactor vessel liquid level for any combination of running RCP's.

6,7. Containment Water Level (Wide Range) and Recirculation Sump Level

Containment Water Level is required for verification and long term surveillance of RCS integrity.

BASES

LCO (continued)

Containment Water Level is used to determine:

- containment level accident diagnosis; and
- when to begin the recirculation procedure.

The LCO requirement for 1 channel of Containment Recirculation sump water level indication is satisfied by either level transmitter designated LT-1251 or LT-1252. The LCO requirement for 1 channel of Containment water level (wide range) indication is satisfied by either level transmitter designated LT-1253 and LT-1254. Normal control room indication will satisfy this requirement.

The refueling water storage tank level (Function 17) provides the diverse variable for measurement for the containment water level. Additionally, 2 channels of containment sump water level indication are available.

8. Containment Pressure (Wide Range)

Containment Pressure (Wide Range) is required for verification of need for and effectiveness of containment spray and fan cooler units.

The LCO requirements for 1 channel of Containment pressure indication is satisfied by pressure transmitters designated PT-1421 or PT-1422. Normal control room indication will satisfy this requirement. Additional containment pressure instrumentation, PT-948A, B & C and PT-949A, B & C, provide a diverse means of establishing containment pressure.

9. Automatic Containment Isolation Valve Position

CIV Position is provided for verification of Containment OPERABILITY and Phase A and Phase B isolation.

When used to verify Phase A and Phase B isolation, the important information is the isolation status of the containment penetrations. The LCO requires one channel of valve closed

BASES

LCO (continued)

position indication in the control room (or at local control stations for valves without control room indication) to be OPERABLE for each containment penetration flow path. If a normally active CIV is known to be closed and deactivated, position indication is not needed to determine status. Therefore, the position indication for valves in this state is not required to be OPERABLE.

Note (a) to the Required Channels states that the Function is not required for isolation valves whose associated penetration is isolated by at least one closed and deactivated automatic valve, closed manual valve, blind flange, or check valve.

Note that non-automatic containment isolation valves are not provided with position indication. As described in the Bases for LCO 3.6.3, "Containment Isolation Valves, containment isolation valves classified as essential and non-automatic are maintained in the open position and are closed after the initial phases of an accident. Emergency procedures are utilized to control the closing of these valves. Non-essential containment isolation valves are maintained in the closed position and may be opened, if necessary, for plant operation and for only as long as necessary to perform the intended function, under administrative controls described in the Bases for LCO 3.6.3.

10. Containment Area Radiation (High Range)

Containment Area Radiation is provided to monitor for the potential of significant radiation releases and to provide release assessment for use by operators in determining the need to invoke site emergency plans. The LCO requirement for 1 channel of Containment Area Radiation (high range) monitoring is satisfied by radiation monitors designated R-25 or R-26.

11. Containment Hydrogen Monitors

Hydrogen Monitors are provided to detect high hydrogen concentration conditions that represent a potential for containment breach from a hydrogen explosion. This variable is also important in verifying the adequacy of mitigating actions.

BASES

LCO (continued)

The LCO requirements for 1 channel of Containment Hydrogen monitoring is satisfied by either containment hydrogen sampling monitor designated HCMC-A or HCMC-B. Hydrogen monitor OPERABILITY requires that the associated containment fan cooler unit (FCU) is OPERABLE. HCMC-A is associated with FCU 32 or 35 and HCMC-B is associated with FCU 31 or 33 or 34.

12. Pressurizer Level

Pressurizer Level 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 that the unit is maintained in a safe shutdown condition.

The LCO requirements for 2 channels of pressurizer level indication is satisfied by any two of the level instruments designated LT-459, LT-460 and LT-461.

13, 14. Steam Generator Water Level (Wide Range and Narrow Range)

SG Water Level is required to monitor operation of decay heat removal via the SGs.

Each Steam Generator (SG) contains 4 transmitters that indicate SG water level. Three transmitters per SG indicate narrow range level which is a span that begins at the top of the tube bundles up to the moisture separator. The remaining level transmitter, the wide range instrument, covers the span from the bottom tube sheet up to the moisture separator.

Requirements for steam generator water level indication assume that two of the four steam generators are required for heat removal.

Wide range SG water level is a Category I, Type A variable used to determine if the SG's are being maintained as an adequate heat sink for decay heat removal. The LCO requirement for 2 channels of wide range water level is satisfied by any two instruments designated LT-417D, LT-427D, LT-437D, and LT-447D.

BASES

LCO (continued)

Narrow range SG water level is a Category I, Type A variable used to determine if the SG's are being maintained as an adequate heat sink for decay heat removal and to maintain the SG level and prevent overfill. It is also used to determine whether SI should be terminated and may be used to diagnose an SG tube rupture event. The LCO requirements for 2 channels of narrow range SG water level is satisfied by any 1 instrument from any two different SGs such that all four SGs have at least one wide range or narrow range instrument:

SG 31	SG 32	SG 33	SG 34
LT-417A	LT-427A	LT-437A	LT-447A
LT-417B	LT-427B	LT-437B	LT-447B
LT-417C	LT-427C	LT-437C	LT-447C

15. Steam Generator Pressure

Each SG contains 3 transmitters that indicate SG pressure. Requirements for steam generator pressure indication assume that two of the four steam generators are required for heat removal. Requiring 1 channel per steam generator of SG pressure provides indication for all SGs.

SG pressure is a Category I, Type A variable used to determine if a high energy secondary line rupture occurred and which steam generator is faulted. SG pressure is also used as diverse indication of RCS cold leg temperature for natural circulation determination.

The LCO requirements for 1 channel per steam generator of pressure indication is satisfied by any 1 indication from the following instruments for each of the four SGs:

SG 31	SG 32	2SG 33	SG 34
PT-419A	PT-429A	PT-439A	PT-449A
PT-419B	PT-429B	PT-439B	PT-449B
PT-419C	PT-429C	PT-439C	PT-449C

BASES

LCO (continued)

16. Condensate Storage Tank (CST) Level

CST Level is provided to ensure water supply for auxiliary feedwater (AFW). The CST provides the ensured safety grade water supply for the AFW System.

CST Level is a Type A variable because the control room indication is the primary indication used by the operator.

The DBAs that require AFW are the loss of electric power, steam line break (SLB), and small break LOCA.

The CST is the initial source of water for the AFW System. However, as the CST is depleted, manual operator action is necessary to replenish the CST or align suction to the AFW pumps to city water.

The LCO requirement for 1 channel of CST level indication is satisfied by either level transmitter designated LT-1128 or LT-1128A. Normal control room indication or displays on the QSPDS in the Control Room will satisfy this requirement. Diverse indication of CST level can be derived from auxiliary feedwater suction pressure indication.

17. Refueling Water Storage Tank (RWST) Level Alarm

Following a LOCA, switchover from the injection phase to the recirculation phase must occur before the RWST empties to prevent damage to the pumps and a loss of cooling capability. For similar reasons, switchover must not occur before there is sufficient water in the containment to support recirculation pump suction. Furthermore, early switchover must not occur to ensure that sufficient borated water is injected from the RWST. The IP3 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 with the RWST level alarm (in conjunction with containment level) as the primary indicator for determining the time for the switchover. Therefore, RWST level alarms are Type A, Category 1 variable. Note that RWST

BASES

LCO (continued)

level indication is a Category 2 instrument as recommended in Regulatory Guide 1.97.

The RWST low-low level alarm setpoint has both upper and lower limits. The lower limit is selected to ensure switchover occurs before the RWST empties, to prevent ECCS pump damage. The high limit also ensures adequate water inventory in the containment sump to provide ECCS pump suction.

Requiring 2 channels of RWST level alarm ensures that the alarm function will be available assuming a single failure of one channel. Diverse indication of RWST level can be derived the post LOCA containment water level.

18, 19, 20, 21. Core Exit Temperature

Core Exit Temperature is required for verification and long term surveillance of core cooling. Core Exit Temperature is also used for unit stabilization and cooldown control. Core exit thermocouples also provide diverse indication for the RCS Hot Leg Temperature.

Four individual channels qualified to satisfy LCO requirements are provided in each quadrant of core. The LCO requirements for core exit thermocouple temperature indication are satisfied by any two channels in each of the 4 core quadrants (i.e., 2 channels per quadrant). Thermocouple readings are obtainable via the QSPDS and at a manually selected display unit in the control room.

Requiring 2 channels per core quadrant provides sufficient channels in each of the 4 quadrants to determine the core radial temperature gradient.

22. Main Steam Line (MSL) Radiation

The MSL radiation monitors are a Type A variable provided to allow detection of a gross secondary side radioactivity release and to provide a means to identify the faulted steam generator. The LCO requirements for MSL radiation indication are satisfied by one channel in each of the 4 MSLs using instruments designated R62A,

BASES

LCO (continued)

R62B, R62C, R62D. Steam generator narrow range level serves as diverse indication for the one monitor per loop provided.

23. Gross Failed Fuel Detector

The gross failed fuel detector is a Type A variable provided to allow determination of reactor coolant system radioactivity concentration. The LCO requires 1 OPERABLE channel and can be satisfied using either R-63A or R-63B.

24. RCS Subcooling

RCS subcooling margin is a Type A variable provided to determine whether to terminate actuated SI or to reinitiate stopped SI, to determine when to terminate reactor coolant pump operation, and for unit stabilization and cooldown control. RCS subcooling margin is calculated and displayed in the plant Qualified Safety Parameter Display System. Diverse indication is available using saturation pressure and steam tables.

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

Note 1 has been added in the ACTIONS to exclude the MODE change restriction of LCO 3.0.4. This exception allows entry into the applicable MODE while relying on the ACTIONS even though the ACTIONS may eventually require unit shutdown. This exception is acceptable due to the passive function of the instruments, the operator's ability to respond to an accident using alternate instruments and methods, and the low probability of an event requiring these instruments.

BASES

ACTIONS (continued)

Note 2 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.

A.1

Condition A applies when one or more Functions have one inoperable required channel. Required Action A.1 requires restoring one channel in the Function(s) to OPERABLE status within 7 days. 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 a required channel 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.

Condition A also applies when one channel of RWST low level alarm (Table 3.3.31-1, Function 17) is inoperable. Required Action A.1 requires restoring the inoperable channel to OPERABLE status within 7 days. The 7 day Completion Time for restoration of redundancy of the alarm function is needed because the IP3 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 with the RWST level alarm (in conjunction with containment sump level) as the primary indicator for determining the time for the switchover.

B.1

Condition B applies when the Required Action or associated Completion Time of Condition A are not met. Required Action B.1 requires entering the appropriate Condition referenced in

BASES

ACTIONS

B.1 (continued)

Table 3.3.3-1 for the channel immediately. The applicable Condition referenced in the Table is Function dependent. Each time an inoperable channel has not met any Required Action of Condition A, and the associated Completion Time has expired, Condition B is entered for that channel and provides for transfer to the appropriate subsequent Condition.

C.1 and C.2

If Condition B exists or if the Required Action and associated Completion Time of Conditions A are not met and Table 3.3.3-1 directs entry into Condition C, 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.

D.1

Alternate means of monitoring neutron flux, condensate storage tank level, main steam line radiation, gross failed fuel, containment isolation valve position indications and containment area radiation are available. These alternate means may be used if the normal PAM channel cannot be restored to OPERABLE status within the allotted time. If these alternate means can be used, the Required Action is not to shut down the unit but rather to follow the directions of Specification 5.6.7, in the Administrative Controls section of the TS. The report provided to the NRC should discuss the alternate means available, 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.

BASES

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.

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.

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.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.3.2

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 measured parameter with the necessary range and accuracy. This SR is modified by a Note that excludes neutron detectors. The calibration method for neutron detectors is described in the Bases of LCO 3.3.1, "Reactor Trip System (RTS) Instrumentation." The Frequency is based on operating experience and consistency with the typical industry refueling cycle.

REFERENCES

1. Safety Evaluation: Conformance to Regulatory Guide 1.97, Revision 3, for Indian Point 3 (TAC No. 51099), dated April 3, 1991.

2. Regulatory Guide 1.97, Revision 3.

3. NUREG-0737, Supplement 1, "TMI Action Items."

4. FSAR, Section 7.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.3:
"Post Accident Monitoring (PAM) Instrumentation"

PART 2:

CURRENT TECHNICAL SPECIFICATION PAGES

Annotated to show differences between CTS and ITS

CTS pages and associated TSCRs annotated for this ITS Specification :

CTS Page No.	Effective Amendment	Annotated Amendment	TSCR No.	TSCR Description	ITS Status of TSCR
3.3-1	154	154	No TSCRs	No TSCRs for this Page	N/A
3.3-2	154	154	No TSCRs	No TSCRs for this Page	N/A
3.3-3	179	179	No TSCRs	No TSCRs for this Page	N/A
3.3-4	139	139	No TSCRs	No TSCRs for this Page	N/A
3.3-5	53	53	No TSCRs	No TSCRs for this Page	N/A
3.3-11	154	154	No TSCRs	No TSCRs for this Page	N/A
3.5-1	26	26	No TSCRs	No TSCRs for this Page	N/A
3.5-2	65	65	IPN 96-124	AOT for ESF Initiation Instrumentation (Needs Supplement)	Incorporated
T 3.5-4(2)	151	151	No TSCRs	No TSCRs for this Page	N/A
T 3.5-5(1)	150	150	No TSCRs	No TSCRs for this Page	N/A
T 3.5-5(2)	100	100	No TSCRs	No TSCRs for this Page	N/A

Technical Specification 3.3.3:
"Post Accident Monitoring (PAM) Instrumentation"

T 3.5-5(3)	100	100	No TSCRs	No TSCRs for this Page	N/A
4.1-1	97	97	No TSCRs	No TSCRs for this Page	N/A
4.1-2	97	97	No TSCRs	No TSCRs for this Page	N/A
4.1-3	148	148	No TSCRs	No TSCRs for this Page	N/A
4.1-4	107	107	No TSCRs	No TSCRs for this Page	N/A
4.1-5	182	107 TSCR 97-156			
T 4.1-1(1)	170 TSCR 98-043	170 TSCR 98-043	IPN 98-043	Instrument Channel Surveillance Intervals Extended to 24 Months	Incorporated
T 4.1-1(2)	169	169	No TSCRs	No TSCRs for this Page	N/A
T 4.1-1(3)	168 TSCR 98-043	168 TSCR 98-043	IPN 98-043	Instrument Channel Surveillance Intervals Extended to 24 Months	Incorporated
T 4.1-1(4)	169 TSCR 98-043	169 TSCR 98-043	IPN 98-043	Instrument Channel Surveillance Intervals Extended to 24 Months	Incorporated
T 4.1-1(5)	169 TSCR 98-043	169 TSCR 98-043	IPN 98-043	Instrument Channel Surveillance Intervals Extended to 24 Months	Incorporated
4.5-2	172 TSCR 98-043	172 TSCR 98-043	IPN 98-043	Instrument Channel Surveillance Intervals Extended to 24 Months	Incorporated

3.3 ENGINEERED SAFETY FEATURES

A1

A2

~~Applicability~~

~~Applies to the operating status of the Engineered Safety Features.~~

~~Objective~~

~~To define those limiting conditions for operating that are necessary: 1) to remove decay heat from the core in emergency or normal shutdown situations; 2) to remove heat from containment in normal operating and emergency situations; 3) to remove airborne iodine from the containment atmosphere following a Design Basis Accident; 4) to minimize containment leakage to the environment subsequent to a Design Basis Accident; 5) to minimize the potential for and consequences of Reactor Coolant System pressure transients.~~

Specification

The following specifications apply except during low temperature physics tests.

LCO 3.3.3 A. Safety Injection and Residual Heat Removal Systems Mode 4 LA.5

T.3.3.3-1, #17 1. ~~The reactor coolant system T_{avg} shall not exceed 200°F unless the following requirements are met:~~

SEE ITS 3.5.4

a. The refueling water storage tank water level shall be a minimum of 35.4 feet, with the water at a boron concentration ≥2400 ppm and ≤2600 ppm.

T 3.3.3-1, #17 b. ~~One refueling water storage tank low level alarm operable and set to alarm between 10.5 feet and 12.5 feet of water in the tank.~~ LA.5

~~in Mode 4~~

SEE CTS MASTER MARKUP

c. One residual heat removal pump and heat exchanger together with the associated piping and valves operable.

d. One recirculation pump together with its associated piping and valves operable.

2. If the Safety Injection and Residual Heat Removal Systems are not restored to meet the requirements of 3.3.A.1 within 1 hour the reactor shall be in the cold shutdown condition within the next 20 hours.

3. ~~The reactor coolant system T_{avg} shall not exceed 350°F unless the~~ following requirements are met: {Mode 1, 2 and 3} - A.1

SEE CTS MASTER MARKUP

a. The refueling water storage tank water level shall be a minimum of 35.4 feet, with the water at a boron concentration ≥2400 ppm and ≤2600 ppm.

b. DELETED

c. The four accumulators are pressurized between 600 and 700 psig and each contains a minimum of 775 ft^3 and a maximum of 815 ft^3 of water at a boron concentration ≥2000 ppm and ≤2600 ppm. Accumulator isolation valves 894A, B, C, and D shall be open and their power supplies deenergized whenever the reactor coolant system pressure is above 1000 psig.

SEE CTS MASTER MARKUP

d. One pressure and one level transmitter shall be operating per accumulator.

e. Three safety injection pumps together with their associated piping and valves are operable.

f. Two residual heat removal pumps and heat exchangers together with their associated piping and valves are operable.

g. Two recirculation pumps together with the associated piping and valves are operable.

h. Valves 856B and 856G in the Safety Injection discharge headers shall be closed and their power supplies de-energized.

i. Valve 1810 in the suction line of the high-level SI pumps and valves 882 and 744 in the suction and discharge lines, respectively, of the residual heat removal pumps shall be open and their power supplies de-energized.

j. Valves 842 and 843 in the mini-flow return line from the discharge of the safety injection pumps to the RWST are de-energized in the open position.

T3.3.3-1, #17

k. Two — A.16 The refueling water storage tank low level alarms are operable and set to alarm between 10.5 feet and 12.5 feet of water in the tank. A-16 LA.4

SEE CTS MASTER MARKUP

l. Valve 883 in the RHR return line to the RWST is de-energized in the closed position.

m. Valves 1870 and 743 in the miniflow line for the Residual Heat Removal Pumps shall be open and their power supplies de-energized.

n. The RHR system is in the ESF alignment with the normal RHR suction line isolated from the RCS.

4. The requirements of 3.3.A.3 may be modified to allow any one of the following components to be inoperable at any one time:

SEE CTS MASTER MARKUP

a. The accumulators may be isolated during the performance of the reactor coolant system hydrostatic tests.

For the purpose of accumulator check valve leakage testing, one accumulator may be isolated at a time, for up to 8 hours, provided the reactor is in the hot shutdown condition.

b. One safety injection pump may be out of service, provided the pump is restored to an operable status within 24 hours.

c. One residual heat removal pump may be out of service, provided the pump is restored to an operable status within 24 hours.

d. One residual heat exchanger may be out of service provided that it is restored to an operable status within 48 hours.

e. Any valve required for the functioning of the system during and following accident conditions may be inoperable provided that it is restored to an operable status within 24 hours and all valves in the system that provide the duplicate function are operable.

f. DELETED

T3.3.3-1 #17 Req. Act A.1

g. One refueling water storage tank low level alarm may be inoperable for up to 7 days provided the other low level alarm is operable.

~~5.~~ If the Safety Injection and Residual Heat Removal Systems are not restored to meet the requirements of 3.3.A.3 within the time periods specified in 3.3.A.4; then:

Req Act B.1

~~a.~~ If the reactor is critical, it shall be in the hot shutdown condition within four hours and the cold shutdown condition within the following 24 hours.

Req Act G.1 G.2

~~b.~~ If the reactor is subcritical, the reactor coolant system temperature and pressure shall not be increased more than 25°F and 100 psi, respectively, over existing values. If the requirements of 3.3.A.3 are not satisfied within an additional 48 hours, the reactor shall be brought to the cold shutdown condition using normal operating procedures. The shutdown shall start no later than the end of the 48 hour period.

6 M4 Mode 3 12 Mode 4 A.16 M.4

6. When the reactor coolant system T_{avg} is greater than 200°F and less than 350°F, the following decay heat removal requirements shall be met:

a. Two residual heat removal pumps together with their associated heat exchangers, piping, and valves shall be operable,

OR

b. A minimum of one residual heat removal pump and heat exchanger and a minimum of one reactor coolant pump and steam generator together with their associated piping and valves, shall be operable,

OR

c. A minimum of two reactor coolant pumps and two steam generators, together with their associated piping and valves, shall be operable,

OR

d. With less than the above operable, initiate corrective action to return the required equipment to an operable status as soon as possible and suspend any operations which would reduce the boron concentration of the reactor coolant system. Otherwise, if sufficient equipment is available, be in cold shutdown within 20 hours.

SEE ITS 3.4.6 ITS 3.4.7 ITS 3.4.8

7. When the reactor coolant T_{avg} is less than 200°F, but not in the refueling operation condition, two residual heat removal pumps, together with their associated heat exchangers, piping and valves, shall be operable.

a. With less than the above operable, initiate corrective action to return the required equipment to an operable status as soon as possible and suspend any operations which would reduce the boron concentration of the reactor coolant system.

b. The above requirements may be suspended during maintenance, modifications, testing, inspection or repair provided that:

1) an alternate means of decay heat removal is available and return of the system within sufficient time to prevent exceeding cold shutdown requirements is assured;

G. Containment Hydrogen Monitoring Systems

T3.3.3-1, #11
T3.3.3-1, Note (c)

1. One hydrogen monitor including a flow path and associated containment fan cocler unit shall be OPERABLE whenever the reactor T_{avg} exceeds 350°F. (A.11)

Req. Act A.1
Req. Act C.1

a. The requirements of 3.3.G.1 can be modified to allow both containment hydrogen monitoring systems to be inoperable for a period not to exceed 7 days.

H. Control Room Ventilation System

1. The control room ventilation system shall be operable at all times when containment integrity is required as per specification 3.6.

2. The requirements of 3.3.H.1 may be modified as follows:

a. The control room ventilation system may be inoperable for a period not to exceed seventy-two hours. At the end of this period, if the mal-condition in the control room ventilation system has not been corrected, the reactor shall be placed in the hot shutdown condition utilizing normal operating procedures. If after an additional 48 hours the mal-condition still exists, the reactor shall be placed in the cold shutdown condition utilizing normal operating procedures.

SEE CTS MASTER MARKUP

3. Two independent toxic gas monitoring systems, with separate channels for detecting chlorine, ammonia, and oxygen shall be operable in accordance with 3.3.H.1 except as specified below. The alarms for ammonia and chlorine shall be adjusted to actuate at ≤35 ppm and ≤3 ppm, respectively.

a. With any channel for a monitored toxic gas inoperable, restore the inoperable channel to operable status within 7 days.

b. If 3.a above cannot be satisfied within the specified time, then within the next 8 hours initiate and maintain operation in the control room of alternate monitoring capability for the inoperable channel.

c. With both channels for a monitored gas inoperable, within 8 hours initiate and maintain operation in the control room of an alternate monitoring system capable of detecting the gas monitored by the inoperable channel.

Amendment No. ~~34~~, ~~80~~, ~~98~~, ~~101~~, ~~108~~, ~~113~~, 154

A.1

3.5 INSTRUMENTATION SYSTEMS

Operational Safety Instrumentation

~~**Applicability**~~

A.2

~~Applies to plant instrumentation systems.~~

~~**Objectives**~~

~~To provide for automatic initiation of the Engineered Safety Features in the event that principal process variable limits are exceeded, and to delineate the conditions of the plant instrumentation and safety circuits necessary to ensure reactor safety.~~

Specification

SEE ITS 3.3.1 and 3.3.2	3.5.1	When the plant is not in the cold shutdown condition, the Engineered Safety Features initiation instrumentation setting limits shall be as stated in Table 3.5-1.
LCO 3.3.3, Table 3.3.3-1, Item 22, MSL Radiation	3.5.2	For instrumentation testing or instrumentation channel failure, plant operation shall be permitted to continue in accordance with Tables 3.5-2 through 3.5-4. No more than one channel of a particular protection channel set shall be tested at the same time. By definition, an instrumentation channel failure shall not be regarded as a channel being tested.
	3.5.3	In the event the number of in-service channels of a particular function is less than the minimum number of Operable Channels (Col. 3), or the Minimum Degree of Redundancy (Col. 4) cannot be achieved, operation shall be limited according to the requirement shown in Column 5 of Tables 3.5-2 through 3.5-4.

SEE ITS 3.3.1 and ITS 3.3.2	3.5.4	In the event of instrumentation channel failure permitted by specification 3.5.2, the Minimum Degree of Redundancy listed in Tables 3.5-2 through 3.5-4 may be reduced by one, but to not less than zero, and the Minimum Number of Operable Channels listed in these tables may be reduced by one, but not to less than one (except as noted in Table 3.5-3) for a period of 8 hours while instrument channels are tested. The failed channel may be blocked to prevent an unnecessary reactor trip during this time. In the case of three loop operation, the out-of-service channel is permitted to be bypassed during the test period.
	3.5.5	The low pressurizer pressure safety injection trip shall be unblocked when the pressurizer pressure is ≥ 2000 psig.
	3.5.6	At least one source range and one intermediate range nuclear instrument channel shall be operable prior to reactor start-up.
LCO 3.3.3 ~~3.5.7~~ Applicability		When the reactor is not in the cold shutdown condition, the instrumentation requirements as stated in Table ~~3.5-5~~ 3.3.3-1 shall be met. Mode 1,2,3 L.1
SEE ITS 3.3.2	3.5.8	A minimum of two channels of containment pressure must be operable when T_{avg} is greater than 350°F.

Amendment No. ~~28~~, 65

TSCR 96-124 not shown

TABLE 3.5-4 (Sheet 2 of 2)

No.	FUNCTIONAL UNIT	1 NO. OF CHANNELS	2 NO. OF CHANNELS TO TRIP	3 MIN. OPERABLE CHANNELS	4 MIN. DEGREE OF REDUNDANCY	5 OPERATOR ACTION IF CONDITIONS IN COLUMN 3 OR 4 CANNOT BE MET
3.	FEEDWATER LINE ISOLATION					
a.	Safety Injection	See	Item	No. 1	of	Table 3.5-3
4.	CONTAINMENT VENT AND PURGE					
a.	Containment Radioactivity High (R11 and R12 monitor)	2	1	1	0	close all containment vent and purge valves when above cold shutdown
5.	PLANT EFFLUENT RADIOIODINE/PARTICULATE SAMPLING (sample line common with monitor R13)	1	NA	1	0	(see note 3)
6.	Main Steam Line Radiation Monitors	1/line	NA	1/line	0 (1/line)	(see note 3)
7.	Wide Range Plant Vent Monitor (R27)	1	NA	1	0	(see note 3)

SEE CTS MASTER MARKUP

T3.3.3-1, #22

A.18

SEE CTS MASTER MARKUP

NOTES

1. If the conditions of Columns 3 or 4 cannot be met, the reactor shall be placed in the hot shutdown condition, utilizing normal operating procedures, within 4 hours of the occurrence. If the conditions are not met within 24 hours of the occurrence, the reactor shall be placed in the cold shutdown condition, or the alternate condition if applicable, within an additional 24 hours.

2. Main steam isolation valves may be closed in lieu of going to cold shutdown if the circuitry associated with closing the valves is the only portion inoperable.

LCO 3.3.3
T.3.3.3-1, #22
Applicability

Req. Act A.1
D.1

3. If the plant vent sampling capability, the wide-range vent monitor or the main steam line radiation monitors is/are: determined to be inoperable when the reactor is ~~above the cold shutdown condition~~ Mode 1, 2 and 3, then restore the sampling/monitoring capability within 72 hours or: L.1
   a) Initiate a pre-planned alternate sampling/monitoring capability as soon as practical, but no later than 72 hours after identification of the failures. If the capability is not restored to operable status within 7 days, then, LA.6
   b) Submit a Special Report to the NRC pursuant to Technical Specification 6.9.2 within 14 days following the event outlining the action taken, the cause of the inoperability and the plans and schedule for restoring the system. A.18

ITS Section 5.6.7 A.1

Add ITS T 3.3.3-1, #9, Automatic Containment Isolation Valve Position — A.9 — M.2

Add ITS T 3.3.3-1, #16, Condensate Storage Tank Level — A.15 — M.3

TABLE 3.5-5 (Sheet 1 of 3)

TABLE OF INDICATORS AND/OR RECORDERS AVAILABLE TO THE OPERATOR

	PARAMETER	1 NO. OF CHANNELS AVAILABLE	2 MIN. NO. OF CHANNELS REQUIRED**	3 INDICATOR/ RECORDER**	
	1) a. Containment Pressure - narrow range	6	2	INDICATOR	LA.1
T3.3.3-1, #8	b. Containment Pressure - wide range	2	1	INDICATOR/ RECORDER	A.8
T3.3.3-1, #17	2) Refueling Water Storage Tank Level	2	1	INDICATOR	A.16
T3.3.3-1, #13	3) Steam Generator Water Level (Narrow Range)	3/Steam Generator	*	INDICATOR	A.13
T3.3.3-1, #14	4) Steam Generator Water Level (Wide Range)	1/Steam Generator	*	RECORDER	A.13
T3.3.3-1, #15	5) Steam Line Pressure (Generator) — A.1	3/steam line	1/steam line	INDICATOR	A.14
T3.3.3-1, #12	6) Pressurizer Water Level	3 — LA.2	2	INDICATOR/ONE CHANNEL IS RECORDED	A.12
	7) RHR Recirculation Flow	4	3	INDICATOR	LA.1
T3.3.3-1, #5	8) Reactor Coolant System Pressure (Wide Range)	1	1	RECORDER	A.5
T3.3.3-1, #3	9) Cold Leg Temperature (Tc) (Wide Range)	4	1	RECORDER	A.4
T3.3.3-1, #2	10) Hot Leg Temperature (Th) (Wide Range)	4 — LA.2	1	RECORDER	A.4
	11) Containment Sump Water level (Narrow Range, Analog)+	2	1	INDICATOR/ RECORDER	LA.1
T3.3.3-1, #7	12) Recirculation Sump Water Level (Narrow Range, Analog)+	2 — LA.2	1	INDICATOR/ RECORDER	A.7
	13) Temperature Sensors in: a. Piping Penetration Area b. Mini-Containment Area c. Steam Gen. Blowdown Heat Exchanger Room d. Auxiliary Boiler Feedwater Pump Bldg.	2/area	1/area	ALARM	LA.1

Amendment No. 38, 87, 100, 150

Add ITS T 3.3.3-1, #23, Gross Failed Fuel Detector — A.19

Add ITS T3.3.3-1, #1, Neutron Flux — A.3 M.1

TABLE 3.5-5 (Sheet 2 of 3)

	PARAMETER	1 NO. OF CHANNELS AVAILABLE	2 MIN. NO. OF CHANNELS REQUIRED**	3 INDICATOR/ RECORDER**	
	14) Level Sensors in Lower Level of Turbine Building	2	1	ALARM	LA.1
T3.3.3-1, #24	15) Reactor Coolant System Subcooling Margin Monitor	1 LA.2	1	RECORDER LA.2	A.20
	16) PORV Position Indicator (Acoustic Monitor)	1/Valve	1/Valve	INDICATOR	
	17) PORV Position Indicator (Limit Switch)	1/Valve	1/Valve****	INDICATOR & ALARM	
	18) PORV Block Valve Position Indicator (Limit Switch)	1/Valve***	1/Valve	INDICATOR	LA.1
	19) Safety Valve Position Indicator (Acoustic Monitor)	1/Valve	1/Valve	INDICATOR	
	20) Auxiliary Feedwater Flow Rate	1/Pump SG	1/Pump SG	INDICATOR	
T3.3.3-1, #6	21) Containment Water Level (Wide Range)	2	1	INDICATOR/ RECORDER	A.7
T3.3.3-1, #11	22) Containment Hydrogen Monitor	2	1	INDICATOR/ RECORDER	A.11
T3.3.3-1, #10	23) High-Range Containment***** Radiation Monitors (R25 R26)	2	1	ALARM LA.2	A.10
T3.3.3-1, # 18, 19, 20, 21	24) Core Exit Thermocouples	4/quad-rant	2/quadrant	INDICATOR LA.2	A.17
T3.3.3-1, # 5	25) Reactor Vessel Level Indication System (RVLIS)	2	1	INDICATOR LA.2	A.6

LA.2

Amendment No. ~~38~~, ~~68~~, ~~78~~, 100

TABLE 3.5-5 (Sheet 3 of 3)

Table 3.3.3-1, Note (b) * One level channel per steam generator (either wide range or narrow range) with at least two wide range channels.

Req. Act A.1 ** Columns 2 and 3 may be modified to allow the instrument channels to be inoperable for up to 7 days ~~and/or the recorder to be inoperable for up to 14 days.~~ LA.7

Table 3.3.3-1 Note (a) *** Except at times when valve operator control circuit is de-energized.

**** Except when the respective block valve is closed.

Req. Act A.1 ***** If the high-range containment radiation monitor is determined to be inoperable when the reactor is ~~above the cold shutdown~~ Mode 1, 2, 3 condition, then restore the monitoring capability within 7 days, L.1

and

a) ~~Initiate an alternate monitoring capability as soon as practical, but no later than 72 hours after identification of the failure of the monitor. If the monitor is not restored to operable status within 7 days,~~ LA.6

then

Req. Act D.1 Spec 5.6.7 b) Submit a Special Report (5.6.7) to the NRC pursuant to Technical Specification ~~6.9.2~~ within 14 days following the event outlining the action taken, the cause of the inoperabiblity and the plans and schedule for restoring the system.

Req. Act A.1 Req. Act C.1 + If both narrow range analog monitor channels are determined to be inoperable, at least one channel will be restored to operable status within ~~30 days~~ 7 days or the plant will be brought to ~~hot shutdown~~ Mode 4 within the next 12 hours. A.7.a M.5

Req. Act C.1, C.2 ~~With the exception of the High Range Containment Radiation Monitors,~~ A.1 if the minimum number of channels required are not restored to meet the above requirements within the time periods specified, then:

Req. Act C.1 1. ~~If the reactor is critical, it shall be brought to the hot shutdown condition utilizing normal operating procedures. The shutdown shall start no later than at the end of the specified time period.~~ M.4

Req. Act C.2 2. ~~If the reactor is subcritical, the reactor coolant system temperature and pressure shall not be increased more than 25°F and 100 psi, respectively, over existing values.~~

3. ~~In either case, if the requirements of Columns 2 and 3 are not satisfied within an additional 48 hours, the reactor shall be brought to the cold shutdown condition utilizing normal operating procedures. The shutdown shall start no later than the end of the 48 hour period.~~ M.4

Mode 3 in 6 hr; Mode 4 in 12 hr

4 SURVEILLANCE REQUIREMENTS

4.1 OPERATIONAL SAFETY REVIEW

Applicability

Applies to items directly related to safety limits and limiting conditions for operation. Performance of any surveillance test outlined in these specifications is not required if the plant condition is the same as the condition into which the plant would be placed by an unsatisfactory result of that test. Failure to perform a surveillance requirement within the allowed surveillance interval (including extensions specified in definition 1.12), shall constitute noncompliance with the operability requirements of the limiting conditions for operation (LCOs). The time limits for associated action requirements are applicable at the time it is identified that a surveillance requirement has not been performed. Action requirements may be delayed for up to 24 hours to permit completion of the missed surveillance when the allowable outage time limits of the action requirements are less than 24 hours (i.e. for LCOs of less than 24 hours, a 24 hour delay period is permitted before entering the LCO; for LCOs greater than 24 hours, no delay period is permitted). A.1

Objective

To specify the minimum frequency and type of surveillance to be applied to plant equipment and conditions.

Specification

A. Calibration, testing, and checking of analog channel and testing of logic channel shall be performed as specified in Table 4.1-1.

B. Sampling and equipment tests shall be conducted as specified in Table 4.1-2 and 4.1-3, respectively. A.1

Basis

A surveillance test is intended to identify conditions in a plant that would lead to a degradation of reactor safety. Should a test reveal such a condition, then the Technical Specifications require that, either immediately or after a specified period of time, the plant be placed in a condition which mitigates or eliminates the consequences of additional related casualties or accidents. If the plant is already in a A.1

A.1

condition which would satisfy the failure criteria of the test, then plant safety is assured and performance of the test yields either meaningless information or information that is not necessary to determine safety limits or limiting conditions for operation of the plant.

Likewise, systems and components are assumed to be operable as defined in paragraph 1.5, and satisfying safety limits or LCOs for a given plant operating condition, when surveillance requirements have been satisfactorily performed within the allowed surveillance interval and extensions as specified in definition 1.12. However, nothing in this provision shall be construed as implying that systems or components are operable when they are found or known to be inoperable although still meeting the surveillance requirements. LCO action requirements associated with operation in a degraded mode are applicable when surveillance requirements have not been completed within the allowed surveillance interval. The time limits of such LCOs apply from the point in time it is identified that a surveillance has not been performed and not at the time the allowed surveillance interval was exceeded.

For a missed surveillance, if the allowable outage time limits of the applicable LCO action requirements are less than 24 hours or a shutdown is required, then a 24-hour delay is permitted in implementing the action requirements. The purpose of the delay is to permit the completion of a missed surveillance before a shutdown or some other remedial measure precludes completion of the surveillance. This allowance of a delay includes consideration of the plant conditions, adequate planning, availability of personnel, the time required to perform the surveillance, and the safety significance of the delay in completing the required surveillance. If a surveillance is not completed within the 24-hour delay, than the time limits of the associated action requirements are applicable at the time. When a surveillance is performed within the 24-hour delay and the Surveillance Requirements are not met (e.g. the system or component is declared inoperable), the time limits of the LCO action requirements are applicable at that time.

Failure to perform the surveillance within the allowed surveillance interval and extension as specified in definition 1.12 is still a violation of the LCO operability requirement subject to enforcement and reportability requirements as may be applicable.

Definition 1.12 establishes the limit for which the specified time interval for Surveillance Requirements may be extended.

It permits an allowable extension of the normal surveillance interval to facilitate surveillance scheduling and consideration of plant operating conditions that may not be suitable for conducting the surveillance; e.g. transient conditions or other ongoing surveillance or maintenance activities. It also provides flexibility to accommodate the length of a fuel cycle for surveillances that are performed at each refueling outage and are specified with an 18-month or 24-month surveillance interval. It is not intended that this provision be used repeatedly as a convenience to extend surveillance intervals beyond that specified for surveillances that are not performed on an 18-month or 24-month basis. Likewise, it is not the intent that 24 month surveillances be performed during power operation unless it is consistent with safe plant operation. The limitation of Definition 1.12 is based on engineering judgement and the recognition that the most probable result of any particular surveillance being performed is the verification of conformance with the Surveillance Requirements. This provision is sufficient to ensure that the reliability ensured through surveillance activities is not significantly degraded beyond that obtained from the specified surveillance interval. The phrase "at least" associated with a surveillance frequency does not negate the 25% extension allowance of Definition 1.12; instead, it permits the performance of more frequent surveillance activities.

Based on experience in operation of both conventional and nuclear plant systems, when the plant is in operation, the minimum checking frequency of once per shift is deemed adequate for reactor and steam system instrumentation.

Calibration

Calibrations are performed to ensure the presentation and acquisition of accurate information.

The nuclear flux (linear level) channels are calibrated daily against a heat balance standard to account for errors induced by changing rod patterns and core physics parameters.

Other channels are subject only to the "drift" errors induced within the instrumentation itself and, consequently, can tolerate longer intervals between calibration. Process system instrumentation errors induced by drift can be expected to remain within acceptable tolerances if recalibration is performed at intervals of 18 or 24 months.

Substantial calibration shifts within a channel (essentially a channel failure) will be revealed during routine checking and testing procedures.

Thus, minimum calibration frequencies of once-per-day for the nuclear flux (linear level) channels, and 18 or 24 months for the process system channels is considered acceptable.

A.1

Testing

The minimum testing frequency for those instrument channels connected to the safety system is based on an average unsafe failure rate of 2.5×10^{-6} failure hrs. per channel. This is based on operating experience at conventional and nuclear plants. An unsafe failure is defined as one which negates channel operability and which, due to its nature, is revealed only when the channel is tested or attempts to respond to a bona fide signal.

For a specified test interval W and an M out of N redundant system with identical and independent channels having a constant failure rate λ, the average availability A is given by:

$$A = \frac{W - Q\,\binom{W}{N-M+2}}{W} = 1 - \frac{N!}{(N-M+2)!\,(M-1)!}(\lambda W)^{N-M+1}$$

where A is defined as the fraction of time during which the system is functional, and Q is the probability of failure of such a system during a time interval W.

For a 2-out-of-3 system A = 0.9999708, assuming a channel failure rate, λ, equal to 2.5×10^{-6} hr $^{-1}$ and a test interval, W, equal to 2160 hrs.

This average availability of the 2-out-of-3 system is high, hence the test interval of one quarter is acceptable.

Because of their greater degree of redundancy, the 1/3 and 2/4 logic arrays provide an even greater measure of protection and are thereby acceptable for the same testing interval. Those items specified for quarterly testing are associated with process components where other means of verification provide additional assurance that the channel is operable, thereby requiring less frequent testing.

~~Specified surveillance intervals for the Reactor Protection System and Engineered Safety Features have been determined in accordance with WCAP - 10271, Supplement 1, "Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System," and WCAP - 10271, Supplement 2, Revision 1, "Evaluation of Surveillance Frequencies and Out of Service Times for the Engineered Safety Features Actuation System," as approved by the NRC and documented in the SERs (letters to J. J. Sheppard from C. O. Thomas, dated February 21, 1985, and to R. A. Newton from C. E. Rossi, dated February 22, 1989). Surveillance intervals were determined based on maintaining an appropriate level of reliability of the Reactor Protection System and Engineered Safety Features instrumentation.~~

DELETED

Amendment No. ~~93~~, ~~107~~, TSCR 97-156

TABLE 4.1-1 (Sheet 1 of 6)

MINIMUM FREQUENCIES FOR CHECKS, CALIBRATIONS AND TESTS OF INSTRUMENT CHANNELS

	Channel Description	Check	Calibrate	Test	Remarks
SEE ITS 3.3.1	1. Nuclear Power Range	S	D (1) M (3)*	Q (2)** Q (4)	1) Heat balance calibration 2) Bistable action (permissive, rod stop, trips) 3) Upper and lower chambers for axial offset 4) Signal to Δ T
	2. Nuclear Intermediate Range	S (1)	N.A.	P (2)	1) Once/shift when in service 2) Verification of channel response to simulated inputs
	3. Nuclear Source Range	S (1)	N.A.	P (2)	1) Once/shift when in service 2) Verification of channel response to simulated inputs
T3.3.3-1, #2 T3.3.3-1, #3	SEE ITS 3.3.1 4. Reactor Coolant Temperature	S ## (2) SR 3.3.3.1	24M SR 3.3.3.2	Q (1)	1) Overtemperature ΔT, overpower ΔT, and low T_{avg} 2) Normal Instrument check interval is once/shift T_{avg} instrument check interval reduced to every 30 minutes when: - T_{avg}-T_{ref} deviation and low T_{avg} alarms are not reset and, - Control banks are above 0 steps
SEE ITS 3.3.1	5. Reactor Coolant Flow	S ##	24M	Q	
T3.3.3-1, #12	6. Pressurizer Water Level	SR 3.3.3.1 S 31 days	SR 3.3.3.2 24M L.2.	Q	SEE ITS 3.3.1
SEE ITS 3.3.1	7. Pressurizer Pressure	S ##	24M	Q	High and Low

A.4

A.12

SEE CTS MASTER MARKUP

31 days — SR 3.3.3.1 — L.2

TABLE 4.1-1 (Sheet 2 of 6)

	Channel Description	Check	Calibrate	Test	Remarks
	8. 6.9 KV Voltage 6.9 KV Frequency	N.A. N.A.	18M 24M	Q Q	Reactor protection circuits only Reactor protection circuits only
	9. Analog Rod Position	S	24M	M	
T3.3.3-1, #13 #14	10. Steam Generator Level	~~S~~ SR 3.3.3.1	SR 3.3.3.2 24M	Q	SEE ITS 3.3.2 A.13
	11. Residual Heat Removal Pump Flow	N.A.	24M	N.A.	
	12. Boric Acid Tank Level	S	24M	N.A.	Bubbler tube rodded during ~~calibration~~
T3.3.3-1, #17	13. Refueling Water Storage Tank Level a. Transmitter b. Indicating Switch	W (LA.1) W	SR 3.3.3.2 18M 6M	N.A. N.A.	Low level alarm Low level alarm A.16
	14a. Containment Pressure - narrow range	S	24M	Q	High and High-High
T3.3.3-1, #8	14b. Containment Pressure - wide range	M SR 3.3.3.1	18M SR 3.3.3.2	N.A.	A.8
	15. Process and Area Radiation Monitoring:				
	a. Fuel Storage Building Area Radiation Monitor (R-5)	D	24M	Q	
	b. Vapor Containment Process Radiation Monitors (R-11 and R-12)	D	24M	Q	
T3.3.3-1, #10	c. Vapor Containment High Radiation Monitors (R-25 and R-26)	D 31 days	24M	Q	SEE RELOCATED CTS L2 A.10
	d. Wide Range Plant Vent Gas Process Radiation Monitor (R-27)	D	24M	Q	

Amendment No. 8, 38, 65, 68, 74, 93, 107, 125, 137, 140, 144, 148, 150, 154, 169

31 days — L.2

SR 3.3.3.1 SR 3.3.3.2

TABLE 4.1-1 (Sheet 3 of 6)

	Channel Description	Check	Calibrate	Test	Remarks
T3.3.3-1, #18	e. Main Steam Lines Process Radiation Monitors (R-62A, R-62B, R-62C, and R-62D)	D 31 days L.2	24M	Q LA.3	A.18
T3.3.3-1, #23	f. Gross Failed Fuel Detectors (R-63A and R-63B)	D 31 days L.2	24M	Q LA.3	A.19
T3.3.3-1, #6 #7	16. Containment Water Level Monitoring System:				
	a. ~~Containment Sump~~	N.A.	24M	N.A.	~~Narrow Range, Analog~~ LA.1
	b. Recirculation Sump	N.A.	24M	N.A.	Narrow Range, Analog A.7
	c. Containment Water Level	N.A. M.8	24M	N.A.	Wide Range
SEE 3.5.1	17. Accumulator Level and Pressure	S	24M	N.A.	
T3.3.3-1, #15	18. Steam Line Pressure L.2	S 31 days	24M	Q	SEE ITS 3.3.2
	19. Turbine First Stage Pressure	S	24M	Q	
SEE ITS 3.3.1 ITS 3.3.2	20a. Reactor Trip Relay Logic	N.A.	N.A.	TM	
	20b. ESF Actuation Relay Logic	N.A.	N.A.	TM	
	21. Turbine Trip Low Auto Stop Oil Pressure	N.A.	24M	N.A.	
	22. DELETED	DELETED	DELETED	DELETED	
	23. Temperature Sensor in Auxiliary Boiler Feedwater Pump Building	N.A.	N.A.	18M	LA.1
	24. Temperature Sensors in Primary Auxiliary Building				
	a. Piping Penetration Area	N.A.	N.A.	24M	
	b. Mini-Containment Area	N.A.	N.A.	24M	
	c. Steam Generator Blowdown Heat Exchanger Room	N.A.	N.A.	24M	

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SEE CTS MASTER MARKUP

TABLE 4.1-1 (Sheet 4 of 6)

	Channel Description	Check	Calibrate	Test	Remarks
	25. Level Sensors in Turbine Building	N.A.	N.A.	24M	
	26. Volume Control Tank Level	N.A.	24M	N.A.	
	27. Boric Acid Makeup Flow Channel	N.A.	24M	N.A.	
	28. Auxiliary Feedwater:				
	a. Steam Generator Level	S	24M	Q	Low-Low
	b. Undervoltage	N.A.	24M	24M	
	c. Main Feedwater Pump Trip	N.A.	N.A.	24M	
T3.3.1-1 #24	~~29.~~ Reactor Coolant System Subcooling Margin Monitor	D 31 days SR 3.3.3.1	24M SR 3.3.3.2	N.A.	L.2 A.20
	30. PORV Position Indicator	N.A.	N.A.	24M	Limit Switch
	31. PORV Position Indicator	D	24M	24M	Acoustic Monitor LA.1
	32. Safety Valve Position Indicator	D	24M	24M	Acoustic Monitor
	33. Auxiliary Feedwater Flow Rate	N.A.	18M	N.A.	
	34. Plant Effluent Radioiodine/ Particulate Sampling	N.A.	N.A.	18M	Sample line common with monitor R-13
	35. Loss of Power				
	a. 480v Bus Undervoltage Relay	N.A.	24M	M	
	b. 480v Bus Degraded Voltage Relay	N.A.	18M	M	
	c. 480v Safeguards Bus Undervoltage Alarm	N.A.	24M	M	
T3.3.3-1 #11	36. Containment Hydrogen Monitors	D 31 days SR 3.3.3.1	Q SR 3.3.3.2	M	LA.3 L.2 A.11

Amendment No. 38, 44, 54, 65, 67, 74, 93, 125, 136, 137, 142, 144, 150, 168, 169, TSCR 98-043

TABLE 4.1-1 (Sheet 5 of 6)

	Channel Description	Check (L.2)	Calibrate	Test	Remarks	
T3.3.3-1 #18,19,20,21	37. Core Exit Thermocouples	(D) (31 days) SR 3.3.3.1	24M SR 3.3.3.2	N.A.	(A.17)	1
SEE CTS MASTER MARKUP	38. Overpressure Protection System (OPS)	D	18M (1)	18M	1) Calibration frequency for OPS sensors (RCS pressure and temperature) is 24 months	
	39. Reactor Trip Breakers	N.A.	N.A.	TM(1)	1) Independent operation of under-voltage and shunt trip attachments	
				24M(2)	2) Independent operation of under-voltage and shunt trip from Control Room manual push-button	
	40. Reactor Trip Bypass Breakers	N.A.	N.A.	(1)	1) Manual shunt trip prior to each use	
				24M(2)	2) Independent operation of under-voltage and shunt trip from Control Room manual push-button	
				24M(3)	3) Automatic undervoltage trip	
SR3.3.3.1 SR3.3.3.2	41. Reactor Vessel Level Indication System (RVLIS)	(D) (31 days) SR 3.3.3.1	24M SR 3.3.3.2	N.A.	(L.2)	(A.6)
	42. Ambient Temperature Sensors Within the Containment Building	D	24M	N.A.		
	43. River Water Temperature # (installed)	S	18M	N.A.	1) Check against installed instrumentation or another portable device	
	44. River Water Temperature # (portable)	S (1)	Q (2)	N.A.	2) Calibrate within 30 days prior to use and quarterly thereafter	
	45. Steam Line Flow	S	24M	Q	Engineered Safety Features circuits only	

Amendment No. 38, 54, 65, 74, 78, 93, 98, 107, 125, 126, 137, 140, 142, 164, 169, (TSCR 98-043)

2. Containment Spray System

a. System tests shall be performed at least once per 24 months. The tests shall be performed with the isolation valves in the spray supply lines at the containment and the spray additive tank isolation valves blocked closed. Operation of the system is initiated by tripping the normal actuation instrumentation.

SEE CTS MASTER MARKUP

b. The spray nozzles shall be checked for proper functioning at least every five years. [See Note A, below]

c. The tests will be considered satisfactory if visual observations indicate all components have operated satisfactorily.

T3.3.1-1* 11

3. Containment Hydrogen Monitoring Systems

a. ~~Containment hydrogen monitoring system tests shall be performed at intervals no greater than six months. The tests shall include drawing a sample from the fan cooler units.~~

b. ~~The above tests will be considered satisfactory if visual observations and control panel indication indicate that all components have operated satisfactorily.~~

LA.3

Note A: Testing of the spray nozzles may be deferred until the next refueling outage (R09), but no later than May 31, 1997.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.3:
"Post Accident Monitoring (PAM) Instrumentation"

PART 3:

DISCUSSION OF CHANGES

Differences between CTS and ITS

DISCUSSION OF CHANGES
ITS SECTION 3.3.3 - POST ACCIDENT MONITORING (PAM) INSTRUMENTATION

ADMINISTRATIVE

A.1 In the conversion of the Indian Point Unit 3 Current Technical Specifications (CTS) to the plant specific Improved Technical Specifications (ITS) certain wording preferences or conventions are adopted which do not result in technical changes (either actual or interpretational). Additionally, editorial changes, reformatting, and revised numbering are adopted to make ITS consistent with the conventions in NUREG-1431, Standard Technical Specifications, Westinghouse Plants, Rev. 1, i.e., the improved Standard Technical Specifications.

The CTS Bases are deleted and replaced with comprehensive ITS Bases designed to support interpretation and implementation of the associated Technical Specifications. The Bases explain, clarify, and document the reasons (i.e., bases) for the associated Technical Specifications, and reflect the IP3 plant specific design, analyses, and licensing basis. In accordance with 10 CFR 50.36(a), the ITS Bases are included with the proposed ITS conversion application; however, deletion of the CTS Bases and the adoption of the ITS Bases is an administrative change with no impact on safety.

A.2 CTS Limiting Conditions for Operation (LCOs) and Surveillance Requirements (SRs) include statements of the objective and the applicability. The CTS statements of objective and applicability are deleted because these statements do not establish any requirements and do not provide any guidance for the application of CTS requirements. Therefore, deletion of these statements has no significant adverse impact on safety.

A.3 CTS dose not include an explicit requirement for PAM instrumentation for neutron flux monitoring although 1 channel of source range and 1 channel of intermediate range indication are required prior to criticality and 4 channels of power range indication are required above cold shutdown.

ITS LCO 3.3.3, Table 3.3.3-1, Function 1, Nuclear Flux, is added to Technical Specifications because this variable was identified as Type A

variable in accordance with Regulatory Guide 1.97 requirements for this PAM function (See 3.3.3, DOC M.1).

A.4 CTS 3.5.7 requires that the PAM instrumentation for each function in CTS Table 3.5-5 be Operable which includes a requirement for **CTS Table 3.5-5, Item 10, Hot Leg Temperature (Th) (Wide Range) and CTS Table 3.5-5, Item 9, Cold Leg Temperature (Tc) (Wide Range)**. ITS LCO 3.3.3, **Table 3.3.3-1, Function 2**, RCS Hot Leg Temperature, and **Function 3**, RCS Cold Leg Temperature, maintain these requirements as follows:

a. CTS 3.5.7 requires that the instrumentation requirements in Table 3.5-5 be met when the reactor is not in the cold shutdown condition (i.e., Modes 1, 2, 3 and 4). ITS LCO 3.3.3 Applicability requires that the LCO 3.3.3 requirements be met in Modes 1, 2, and 3 only. This is a less restrictive change (see ITS 3.3.3, DOC L.1).

b. CTS Table 3.5-5 specifies that the number of channels available for each of these functions is 4 (i.e., 1 per loop) and that the minimum number of required channels is 1. ITS Table 3.3.3-1 maintains this requirement. Requirements for single failure tolerance and channel diversity are controlled administratively.

c. CTS Table 3.5-5 establishes an AOT of 7 days for PAM instrument channels (and 14 days for the associated recorder, see ITS 3.3.3, DOC LA.7) if the one required channel is not Operable (i.e., loss of function). ITS 3.3.3, Required Action A.1, maintains the 7 day AOT when one required channel of a PAM function is not Operable.

CTS Table 3.5-5 requires a plant shutdown if the requirements and/or Required Actions and Completion Times associated with the Th and Tc functions are not met. ITS 3.3.3, Required Actions C.1 and C.2 maintain this requirement; however the Completion Times for the shutdown in ITS 3.3.3 are more restrictive (see ITS 3.3.3, DOC M.4). CTS Table 3.5-5 requires the plant be placed in cold shutdown when requirements are not met. ITS 3.3.3, Required Action C.2, requires that the plant be placed in Mode 4 when requirements are not met which is consistent with the change in

Applicability for PAM instrumentation (See ITS 3.3.3, DOC L.1).

d. CTS Table 4.1-1 does not identify an explicit requirement for periodic testing of the RCS hot leg and cold leg wide range temperature instruments required by CTS Table 3.5-5, Items 9 and 10. ITS SR 3.3.3.1 and SR 3.3.3.2 are added to require a Channel Check every 31 days a Channel Calibration every 24 months. This is a more restrictive change (See ITS 3.3.3, DOC M.6).

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated description and justification.

A.5 CTS 3.5.7 requires that the PAM instrumentation for each function in CTS Table 3.5-5 be Operable which includes a requirement for **CTS Table 3.5-5, Item 8, RCS Pressure (Wide Range)**. ITS **LCO 3.3.3, Table 3.3.3-1, Function 4**, RCS Pressure (Wide Range), maintains this requirement as follows:

a. CTS 3.5.7 requires that the instrumentation requirement in Table 3.5-5 be met when the reactor is not in the cold shutdown condition (i.e., Modes 1, 2, 3 and 4). ITS LCO 3.3.3 Applicability requires that the LCO 3.3.3 requirements be met in Modes 1, 2, and 3 only. This is a less restrictive change (see ITS 3.3.3, DOC L.1).

b. CTS Table 3.5-5 specifies that the number of channels available for this function is 1 and the minimum number of required channels is 1. ITS Table 3.3.3-1 maintains this requirement. Requirements for single failure tolerance and channel diversity are controlled administratively. The ITS bases are revised to recognize that 2 RCS pressure (wide range) channels (PT-402 and PT-403) are available.

c. CTS Table 3.5-5 establishes an AOT of 7 days for PAM instrument channels (and 14 days for the associated recorder, see ITS 3.3.3, DOC LA.7) if the one required channel is not Operable (i.e., loss of function). ITS 3.3.3, Required Action A.1, maintains the 7 day

AOT when one required channel of a PAM function is not Operable.

CTS Table 3.5-5 requires a plant shutdown if the requirements and/or Required Actions and Completion Times associated with the RCS wide range pressure functions are not met. ITS 3.3.3, Required Actions C.1 and C.2 maintain this requirement; however the Completion Times for the shutdown in ITS 3.3.3 are more restrictive (see ITS 3.3.3, DOC M.4). CTS Table 3.5-5 requires the plant be placed in cold shutdown when requirements are not met. ITS 3.3.3, Required Action C.2, requires that the plant be placed in Mode 4 when requirements are not met which is consistent with the change in Applicability for PAM instrumentation (See ITS 3.3.3, DOC L.1).

d. CTS Table 4.1-1 does not identify an explicit requirement for periodic testing of the RCS Pressure instrument required by CTS Table 3.5-5, Item 8. ITS SR 3.3.3.1 and SR 3.3.3.2 are added to require a Channel Check every 31 days a Channel Calibration every 24 months. This is a more restrictive change (see ITS 3.3.3, DOC M.6).

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated description and justification.

A.6 CTS 3.5.7 requires that the PAM instrumentation for each function in CTS Table 3.5-5 be Operable which includes a requirement for **CTS Table 3.5-5, Item 25, Reactor Vessel Level (RVLIS)**. ITS **LCO 3.3.3, Table 3.3.3-1, Function 5, Reactor Vessel Level (RVLIS)**, maintains this requirement as follows:

a. CTS 3.5.7 requires that the instrumentation requirements in Table 3.5-5 be met when the reactor is not in the cold shutdown condition (i.e., Modes 1, 2, 3 and 4). ITS LCO 3.3.3 Applicability requires that the LCO 3.3.3 requirements be met in Modes 1, 2, and 3 only. This is a less restrictive change (see ITS 3.3.3, DOC L.1).

b. CTS Table 3.5-5 specifies that the number of channels available for this function is 2 and the minimum number of required channels is 1. ITS Table 3.3.3-1 maintains this requirement. Requirements for single failure tolerance and channel diversity are controlled administratively.

c. CTS Table 3.5-5 establishes an AOT of 7 days for PAM instrument channels (and 14 days for the associated recorder, see ITS 3.3.3, DOC LA.7) if the one required channel is not Operable (i.e., loss of function). ITS 3.3.3, Required Action A.1, maintains the 7 day AOT when one required channel of a PAM function is not Operable.

CTS Table 3.5-5 requires a plant shutdown if the requirements and/or Required Actions and Completion Times associated with the RVLIS functions are not met. ITS 3.3.3, Required Actions C.1 and C.2 maintain this requirement; however the Completion Times for the shutdown in ITS 3.3.3 are more restrictive (see ITS 3.3.3, DOC M.4). CTS Table 3.5-5 requires the plant be placed in cold shutdown when requirements are not met. ITS 3.3.3, Required Action C.2, requires that the plant be placed in Mode 4 when requirements are not met which is consistent with the change in Applicability for PAM instrumentation (See ITS 3.3.3, DOC L.1).

d. CTS Table 4.1-1, Item 41, requires a Channel Check every 24 hours and a Channel Calibration every 24 months. ITS SR 3.3.3.1 and SR 3.3.3.2 maintain these requirements; however, ITS SR 3.3.3.1 reduces the frequency for the Channel Check to once per 31 days. This reduction in the required Frequency for a Channel Check is a less restrictive change (see ITS 3.3.3, DOC L.2).

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated description and justification.

A.7 CTS 3.5.7 requires that the PAM instrumentation for each function in CTS Table 3.5-5 be Operable which includes a requirement for **CTS Table 3.5-5, Item 12, Containment Recirculation Sump Water Level (Narrow Range), and CTS Table 3.5-5, Item 21, Containment Water Level (Wide Range).** ITS

LCO 3.3.3, Table 3.3.3-1, Function 6, Containment Water Level(Wide Range), and Function 7, Containment Water Level (Recirculation Sump), maintain the existing requirements for narrow range and wide range containment level indication as follows:

a. CTS 3.5.7 requires that the instrumentation requirements in Table 3.5-5 be met when the reactor is not in the cold shutdown condition (i.e., Modes 1, 2, 3 and 4). However, CTS Table 3.5-5, Note +, specifies that if requirements for CTS Table 3.5-5, Item 12, Recirculation Sump Water Level (Narrow Range), are not met, then the reactor must be placed be placed in hot shutdown (i.e., Mode 3). This Action implicitly establishes an applicability of Modes 1 and 2 for CTS Table 3.5-5, Item 12. ITS LCO 3.3.3 Applicability requires that the LCO 3.3.3 requirements be met in Modes 1, 2, and 3. This is a more restrictive change for CTS Table 3.5-5, Item 21, Containment Water Level (Wide Range).

b. CTS Table 3.5-5 specifies that the number of channels available for each of these functions is 2 and the minimum number of required channels for each of these functions is 1. ITS Table 3.3.3-1 maintains this requirement. Requirements for single failure tolerance and channel diversity are controlled administratively.

c. For CTS Table 3.5-5, Item 21, Containment Water Level (Wide Range), CTS Table 3.5-5 establishes an AOT of 7 days for PAM instrument channels (and 14 days for the associated recorder, see ITS 3.3.3, DOC LA.7) if the one required channel is not Operable (i.e., loss of function). ITS 3.3.3, Required Action A.1, maintains the 7 day AOT when one required channel of a PAM function is not Operable.

For CTS Table 3.5-5, Item 12, Containment Recirculation Sump Water Level (Narrow Range), CTS Table 3.5-5, Note +, establishes an AOT of 30 days for loss of containment sump narrow range indication (i.e. both the Recirculation sump narrow range and the containment sump narrow range). ITS 3.3.3, Required Action A.1, establishes a 7 day AOT when all required channels of containment narrow range indication function are not Operable. This is a more restrictive

change (See ITS 3.3.3, DOC M.5).

CTS Table 3.5-5 requires a plant shutdown if the requirements and/or Required Actions and Completion Times associated with the containment level functions are not met. ITS 3.3.3, Required Actions C.1 and C.2 maintain this requirement; however the Completion Times for the shutdown in ITS 3.3.3 are more restrictive (see ITS 3.3.3, DOC M.4). CTS Table 3.5-5 requires the plant be placed in cold shutdown when requirements are not met. ITS 3.3.3, Required Action C.2, requires that the plant be placed in Mode 4 when requirements are not met which is consistent with the change in Applicability for PAM instrumentation (See ITS 3.3.3, DOC L.1).

d. CTS Table 4.1-1, Item 16.b and 16.c, require that CTS Table 3.5-5, Item 12, Containment Recirculation Sump Water Level (Narrow Range), and CTS Table 3.5-5, Item 21, Containment Water Level (Wide Range), are calibrated every 24 months. ITS SR 3.3.3.2 maintains this requirement. There is no CTS requirement for periodic Channel Checks of these functions, probably because there is no indicated level during normal operation. ITS SR 3.3.3.1 establishes a new requirement to perform a Channel Check of these functions every 31 days to ensure that there is no indication of channel failure. This is a more restrictive change (see ITS 3.3.3, DOC M.6).

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated description and justification.

A.8 CTS 3.5.7 requires that the PAM instrumentation for each function in CTS Table 3.5-5 be Operable which includes a requirement for **CTS Table 3.5-5, Item 1.b, Containment Pressure-Wide Range**. ITS **LCO 3.3.3, Table 3.3.3-1, Function 8, Containment Pressure**, maintains this requirement as follows:

a. CTS 3.5.7 requires that the instrumentation requirement in Table 3.5-5 be met when the reactor is not in the cold shutdown

condition (i.e., Modes 1, 2, 3 and 4). ITS LCO 3.3.3 Applicability requires that the LCO 3.3.3 requirements be met in Modes 1, 2, and 3 only. This is a less restrictive change (see ITS 3.3.3, DOC L.1).

b. CTS Table 3.5-5 specifies that the number of channels available for this function is 2 and the minimum number of required channels is 1. ITS Table 3.3.3-1 maintains this requirement. Requirements for single failure tolerance and channel diversity are controlled administratively.

c. CTS Table 3.5-5 establishes an AOT of 7 days for PAM instrument channels (and 14 days for the associated recorder, see ITS 3.3.3, DOC LA.7) if the one required channel is not Operable (i.e., loss of function). ITS 3.3.3, Required Action A.1, maintains the 7 day AOT when one required channel of a PAM function is not Operable.

CTS Table 3.5-5 requires a plant shutdown if the requirements and/or Required Actions and Completion Times associated with the Containment Pressure function is not met. ITS 3.3.3, Required Actions C.1 and C.2 maintain this requirement; however the Completion Times for the shutdown in ITS 3.3.3 are more restrictive (see ITS 3.3.3, DOC M.4). CTS Table 3.5-5 requires the plant be placed in cold shutdown when requirements are not met. ITS 3.3.3, Required Action C.2, requires that the plant be placed in Mode 4 when requirements are not met which is consistent with the change in Applicability for PAM instrumentation (See ITS 3.3.3, DOC L.1).

d. CTS Table 4.1-1, Item 14.b, requires a Channel Check every 31 days and a Channel Calibration every 18 months for CTS Table 3.5-5, Item 1.b, Containment Pressure-Wide Range. ITS SR 3.3.3.1 and SR 3.3.3.2 maintain these requirements.

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated description and justification.

A.9 CTS dose not include an explicit requirement for PAM instrumentation for automatic containment isolation valve position indication. ITS LCO 3.3.3, Table 3.3.3-1, Function 9, Automatic Containment Isolation Valve Position Indication, is added to Technical Specifications because this variable was identified as Type A variable in accordance with Regulatory Guide 1.97 requirements for this PAM function (See 3.3.3, DOC M.2).

A.10 CTS 3.5.7 requires that the PAM instrumentation for each function in CTS Table 3.5-5 be Operable which includes a requirement for **CTS Table 3.5-5, Item 23, High-Range Containment Radiation Monitors (R25, R26)**. ITS **LCO 3.3.3, Table 3.3.3-1, Function 10, Containment Area Radiation (High Range)**, maintains this requirement as follows:

a. CTS 3.5.7 requires that the instrumentation requirement in Table 3.5-5 be met when the reactor is not in the cold shutdown condition (i.e., Modes 1, 2, 3 and 4). ITS LCO 3.3.3 Applicability requires that the LCO 3.3.3 requirements be met in Modes 1, 2, and 3 only. This is a less restrictive change (see ITS 3.3.3, DOC L.1).

b. CTS Table 3.5-5 specifies that the number of channels available for this function is 2 and the minimum number of required channels is 1. ITS Table 3.3.3-1 maintains this requirement. Requirements for single failure tolerance and channel diversity are controlled administratively.

c. CTS Table 3.5-5, Note *****, establishes an AOT of 7 days for CTS Table 3.5-5, Item 23, High-Range Containment Radiation Monitor if the one required channel is not Operable (i.e., loss of function). ITS 3.3.3, Required Action A.1, maintains the 7 day AOT when one required channel of a PAM function is not Operable.

   CTS Table 3.5-5 requires initiation of alternate monitoring capability within 72 hours if the one required channel of the Containment Area Radiation function is not Operable (i.e., loss of function). This requirement is relocated to the FSAR and will be implemented by plant procedures (See ITS 3.3.3, DOC LA.6).

CTS Table 3.5-5, Note ***** (b), requires a special report to the NRC within 14 days explaining the preplanned alternate method of monitoring, the cause of the inoperability, and the plans and schedule for restoration if CTS Table 3.5-5, Item 23, High-Range Containment Radiation Monitors (R25, R26) is inoperable for more than 7 days. ITS LCO 3.3.3, Required Action D.1, maintains this requirement by requiring initiation of action in accordance with ITS Specification 5.6.7.

d. CTS Table 4.1-1, Item 15.c, requires a Channel Check every 24 hours and a Channel Calibration every 24 months for CTS Table 3.5-5, Item 23, High-Range Containment Radiation Monitors (R25, R26). ITS SR 3.3.3.1 and SR 3.3.3.2 maintain these requirements; however, ITS SR 3.3.3.1 reduces the frequency for the Channel Check to once per 31 days. This reduction in the required Frequency for a Channel Check is a less restrictive change (see ITS 3.3.3, DOC L.2).

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated description and justification.

A.11 CTS 3.5.7 requires that the PAM instrumentation for each function in CTS Table 3.5-5 be Operable which includes a requirement for **CTS Table 3.5-5, Item 22, Containment Hydrogen Monitor**. **CTS 3.3.G, Containment Hydrogen Monitoring Systems**, has the same requirements except that CTS 3.3.G.1 specifies that Containment Hydrogen Monitor Operability requires Operability of an associated fan cooler unit (FCU). ITS **LCO 3.3.3, Table 3.3.3-1, Function 11, Containment Hydrogen Monitors**, and associated Note (c) maintain this requirement for hydrogen monitoring and the associated FCU as follows:

a. CTS 3.5.7 requires that the instrumentation requirement in Table 3.5-5 be met when the reactor is not in the cold shutdown condition (i.e., Modes 1, 2, 3 and 4). CTS 3.3.G requires this function is Operable when RCS temperature exceeds 350°F (i.e., Modes 1, 2 and 3). ITS LCO 3.3.3 Applicability requires that the LCO 3.3.3 requirements be met in Modes 1, 2, and 3 only. This is

a less restrictive change from the requirements of CTS 3.5.7 (see ITS 3.3.3, DOC L.1).

b. CTS Table 3.5-5 specifies that the number of channels available for this function is 2 and the minimum number of required channels is 1. CTS 3.3.G.1 requires one hydrogen monitor. ITS Table 3.3.3-1 maintains this requirement. Requirements for single failure tolerance and channel diversity are controlled administratively. ITS Table 3.3.3-1, Note (c) maintains the CTS 3.3.G.1 requirement that Hydrogen monitor Operability requires that the associated containment fan cooler unit (FCU) is OPERABLE. HCMC-A is associated with FCU 32 or 35 and HCMC-B is associated with FCU 31 or 33 or 34.

c. CTS 3.3.G.1.a and CTS Table 3.5-5 establish an AOT of 7 days for Containment Hydrogen Monitors if the one required channel is not Operable (i.e., loss of function). ITS 3.3.3, Required Action A.1, maintains the 7 day AOT when one required channel of a PAM function is not Operable.

CTS Table 3.5-5 requires a plant shutdown if the requirements and/or Required Actions and Completion Times associated with the hydrogen monitor function are not met. CTS 3.3.G.1.a does not specify any actions if the requirement for one containment hydrogen monitor is not met; therefore, this condition would require an immediate plant shutdown. ITS 3.3.3, Required Actions C.1 and C.2 maintain the requirement for plat shutdown; however the Completion Times for the shutdown in ITS 3.3.3 are more restrictive (see ITS 3.3.3, DOC M.4) than those in CTS Table 3.5-5. This is an administrative change with no adverse impact on safety because ITS 3.3.3, Required Actions C.1 and C.2, are a reasonable interpretation of the requirements of CTS 3.3.G.1.a.

d. CTS Table 4.1-1, Item 36, requires a containment hydrogen monitor Channel Check every 24 hours and a Channel Calibration every 24 months. ITS SR 3.3.3.1 and SR 3.3.3.2 maintain these requirements; however, ITS SR 3.3.3.1 reduces the frequency for the Channel Check to once per 31 days. This reduction in the required Frequency for the containment hydrogen monitor Channel

Check is a less restrictive change (see ITS 3.3.3, DOC L.2).

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated description and justification.

A.12 CTS 3.5.7 requires that the PAM instrumentation for each function in CTS Table 3.5-5 be Operable which includes a requirement for **CTS Table 3.5-5, Item 6, Pressurizer Water Level**. ITS LCO 3.3.3, Table 3.3.3-1, Function 12,Pressurizer Water Level, maintains this requirement as follows:

a. CTS 3.5.7 requires that the instrumentation requirements in Table 3.5-5 be met when the reactor is not in the cold shutdown condition (i.e., Modes 1, 2, 3 and 4). ITS LCO 3.3.3 Applicability requires that the LCO 3.3.3 requirements be met in Modes 1, 2, and 3 only. This is a less restrictive change (see ITS 3.3.3, DOC L.1).

b. CTS Table 3.5-5 specifies that the number of channels available for this function is 3 and the minimum number of required channels is 2. CTS requires 2 channels as the minimum Operable because pressurizer level provides control functions that may be the initiator the event. Therefore, the CTS requirement ensures the indication will be available following any event. ITS Table 3.3.3-1 maintains this requirement. Requirements for single failure tolerance and channel diversity are controlled administratively.

c. CTS Table 3.5-5 establishes an AOT of 7 days for PAM instrument channels (and 14 days for the associated recorder, see ITS 3.3.3, DOC LA.7) if one or both of the required channels are not Operable (i.e., potential loss of function). ITS 3.3.3, Required Action A.1, maintains the 7 day AOT when one required channel of a PAM function is not Operable.

CTS Table 3.5-5 requires a plant shutdown if the requirements and/or Required Actions and Completion Times associated with the

function are not met. ITS 3.3.3, Required Actions C.1 and C.2 maintain this requirement; however the Completion Times for the shutdown in ITS 3.3.3 are more restrictive (see ITS 3.3.3, DOC M.4). CTS Table 3.5-5 requires the plant be placed in cold shutdown when requirements are not met. ITS 3.3.3, Required Action C.2, requires that the plant be placed in Mode 4 when requirements are not met which is consistent with the change in Applicability for PAM instrumentation (See ITS 3.3.3, DOC L.1).

d. CTS Table 4.1-1, Item 6, requires a pressurizer level Channel Check every 24 hours and a Channel Calibration every 24 months. ITS SR 3.3.3.1 and SR 3.3.3.2 maintain these requirements; however, ITS SR 3.3.3.1 reduces the frequency for the Channel Check to once per 31 days. This reduction in the required Frequency for a Channel Check is a less restrictive change (see ITS 3.3.3, DOC L.2).

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated description and justification.

A.13 CTS 3.5.7 requires that the PAM instrumentation for each function in CTS Table 3.5-5 be Operable which includes a requirement for **CTS Table 3.5-5, Item 3, Steam Generator Water Level (Narrow Range) and CTS Table 3.5-5, Item 4, Steam Generator Water Level (Wide Range)**. ITS **LCO 3.3.3, Table 3.3.3-1, Function 13**, SG Water level (narrow Range), and **Function 12**, SG Water level (wide Range), maintain these requirements as follows:

a. CTS 3.5.7 requires that the instrumentation requirements in Table 3.5-5 be met when the reactor is not in the cold shutdown condition (i.e., Modes 1, 2, 3 and 4). ITS LCO 3.3.3 Applicability requires that the LCO 3.3.3 requirements be met in Modes 1, 2, and 3 only. This is a less restrictive change (see ITS 3.3.3, DOC L.1).

b. CTS Table 3.5-5 specifies that the number of channels available for each of these functions is 3 per SG for the narrow range channels and 1 per SG for the wide range channels. CTS Table 3.5-

5. Note *, specifies that the minimum number of required channels is "one level channel per steam generator (either wide range or narrow range) with at least two wide range channels. ITS Table 3.3.3-1 maintains this requirement. Requirements for single failure tolerance and channel diversity are controlled administratively.

c. CTS Table 3.5-5 establishes an AOT of 7 days for PAM instrument channels (and 14 days for the associated recorder, see ITS 3.3.3, DOC LA.7) if the minimum number of required channels is not Operable (i.e., loss of function). ITS 3.3.3, Required Action A.1, maintains the 7 day AOT when one required channel of a PAM function is not Operable.

CTS Table 3.5-5 requires a plant shutdown if the requirements and/or Required Actions and Completion Times associated with the SG water level indication functions are not met. ITS 3.3.3, Required Actions C.1 and C.2 maintain this requirement; however the Completion Times for the shutdown in ITS 3.3.3 are more restrictive (see ITS 3.3.3, DOC M.4). CTS Table 3.5-5 requires the plant be placed in cold shutdown when requirements are not met. ITS 3.3.3, Required Action C.2, requires that the plant be placed in Mode 4 when requirements are not met which is consistent with the change in Applicability for PAM instrumentation (See ITS 3.3.3, DOC L.1).

d. CTS Table 4.1-1, Item 10, requires a Channel Check once every 12 hours and a Channel Calibration every 24 months for the SG water level instruments to satisfy requirements for the ESFAS system. ITS SR 3.3.3.1 establishes a new requirement to perform a Channel Check of the PAM instruments every 31 days for each required PAM instrument channel that is normally energized and ITS 3.3.2.1 maintains the existing requirement to perform a Channel Check every 12 hours. ITS SR 3.3.3.2 and ITS SR 3.3.2.12 maintain the requirement for a Channel Calibration for the SG water level instruments every 24 months. Therefore, there is no change to the existing surveillance requirements.

Each of the changes described above is an administrative change with no

adverse impact on safety except as noted with a cross reference to the associated description and justification.

A.14 CTS 3.5.7 requires that the PAM instrumentation for each function in CTS Table 3.5-5 be Operable which includes a requirement for **CTS Table 3.5-5, Item 5, Steam Line Pressure**. ITS LCO 3.3.3, Table 3.3.3-1, Function 15, Steam Generator Pressure, maintains this requirement as follows:

a. CTS 3.5.7 requires that the instrumentation requirements in Table 3.5-5 be met when the reactor is not in the cold shutdown condition (i.e., Modes 1, 2, 3 and 4). ITS LCO 3.3.3 Applicability requires that the LCO 3.3.3 requirements be met in Modes 1, 2, and 3 only. This is a less restrictive change (see ITS 3.3.3, DOC L.1).

b. CTS Table 3.5-5 specifies that the number of channels available for this function is 3 per steam line and the minimum number of required channels is 1 per steam line. ITS Table 3.3.3-1 maintains this requirement. Requirements for single failure tolerance and channel diversity are controlled administratively.

c. CTS Table 3.5-5 establishes an AOT of 7 days for PAM instrument channels (and 14 days for the associated recorder, see ITS 3.3.3, DOC LA.7) if the one required channel is not Operable (i.e., loss of function). ITS 3.3.3, Required Action A.1, maintains the 7 day AOT when all required channels of a PAM function are not Operable.

CTS Table 3.5-5 requires a plant shutdown if the requirements and/or Required Actions and Completion Times associated with the function are not met. ITS 3.3.3, Required Actions C.1 and C.2 maintain this requirement; however the Completion Times for the shutdown in ITS 3.3.3 are more restrictive (see ITS 3.3.3, DOC M.4). CTS Table 3.5-5 requires the plant be placed in cold shutdown when requirements are not met. ITS 3.3.3, Required Action C.2, requires that the plant be placed in Mode 4 when requirements are not met which is consistent with the change in Applicability for PAM instrumentation (See ITS 3.3.3, DOC L.1).

d. CTS Table 4.1-1, Item 18, requires a Channel Check once every 12 hours and a Channel Calibration every 24 months for the SG pressure instruments to satisfy requirements for the ESFAS system. ITS SR 3.3.3.1 establishes a new requirement to perform a Channel Check of the PAM instruments every 31 days for each required PAM instrument channel that is normally energized and ITS 3.3.2.1 maintains the existing requirement to perform a Channel Check every 12 hours. ITS SR 3.3.3.2 and ITS SR 3.3.2.12 maintain the requirement for a Channel Calibration for the SG pressure instruments every 24 months. Therefore, there is no change to the existing surveillance requirements..

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated description and justification.

A.15 CTS dose not include an explicit requirement for PAM instrumentation for condensate storage tank level. ITS LCO 3.3.3, Table 3.3.3-1, Function 16, Condensate Storage Tank Level, is added to Technical Specifications because this variable was identified as Type A variable in accordance with Regulatory Guide 1.97 requirements for this PAM function (See 3.3.3, DOC M.3).

A.16 CTS 3.5.7 requires that the PAM instrumentation for each function in CTS Table 3.5-5 be Operable which includes a requirement for **CTS Table 3.5-5, Item 2, Refueling Water Storage Tank Level Alarms**. Additionally, **CTS 3.3.A.3.k** requires that RWST low level alarms are operable (See ITS 3.3.3, DOC LA.4). ITS **LCO 3.3.3, Table 3.3.3-1, Item 2, Refueling Water Storage Tank Level**, maintain this requirement as follows:

a. CTS 3.5.7 requires that the instrumentation requirement in Table 3.5-5 be met when the reactor is not in the cold shutdown condition (i.e., Modes 1, 2, 3 and 4). CTS 3.3.A.3.k requires this function is Operable when RCS temperature exceeds 350°F (i.e., Modes 1, 2 and 3) (See ITS 3.3.3, DOC LA.5). ITS LCO 3.3.3 Applicability requires that the LCO 3.3.3 requirements be met in Modes 1, 2, and 3 only. This is a less restrictive change from

the requirements of CTS 3.5.7 (see ITS 3.3.3, DOC L.1).

b. CTS Table 3.5-5 specifies that the number of channels available for this function is 2 and the minimum number of required channels is 1. CTS 3.3.A.3.k requires that two RWST low level alarms are Operable. ITS Table 3.3.3-1 establishes the RWST level alarm requirement for this function consistent with CTS 3.3.A.3.k by requiring Operability of 2 channels. Requiring 2 channels of this function ensures that indication will be available assuming a single failure of one channel.

c. CTS Table 3.5-5, Item 2, RWST Level Alarm, does not require redundant channels for so there is no required action for loss of redundancy. CTS 3.3.A.3.k does require redundant Operable channels of RWST low level alarm and CTS 3.3.A.4.g specifies that one RWST low level alarm may be inoperable for up to 7 days provided the other low level alarm is operable. ITS LCO 3.3.3, Required Action A.1, maintains the AOT of 7 days when one of the two RWST low level alarms is inoperable. Consistent with current requirements, if the RWST low level alarm is not restored to Operable within the AOT, ITS LCO 3.3.3, Required Action B.1, requires immediate initiation of a reactor shutdown. This is an administrative change with no adverse impact on safety because it is a reasonable interpretation of the equivalent CTS requirement. ITS 3.3.3, Required Actions B.1 and C.1 and C.2 implement this requirement for plat shutdown; however the Completion Times for the shutdown in ITS 3.3.3 are more restrictive (see ITS 3.3.3, DOC M.4) than those in CTS Table 3.5-5.

CTS Table 3.5-5 establishes an AOT of 7 days if the one required channel of the RWST level alarm (i.e., loss of function); however, CTS 3.3.A.4.g and CTS 3.3.A.5 require immediate initiation of a reactor shutdown if there is a loss of RWST low level alarm function. ITS 3.3.3, Required Actions B.1 and C.1 and C.2 maintain this requirement for immediate plant shutdown when there is a loss of RWST low level alarm function; however the Completion Times for the shutdown in ITS 3.3.3 are more restrictive (see ITS 3.3.3, DOC M.4) than those in CTS Table 3.5-5.

d. CTS Table 4.1-1, Item 13, requires an RWST level Channel Check every 7 days and an RWST level Channel Calibration of the alarm transmitter every 18 months and the indicating switch every 6 months. ITS SR 3.3.3.1 and SR 3.3.3.2 maintain these requirements; however, ITS SR 3.3.3.1 reduces the frequency for the Channel Check to once per 31 days. This reduction in the required Frequency for the RWST level Channel Check is a less restrictive change (see ITS 3.3.3, DOC L.2).

CTS 3.3.A.3.k establishes acceptance criteria for the refueling water storage tank (RWST) low level alarms at between 10.5 feet and 12.5 feet of water in the tank and CTS Table 4.1-1, Item 13, requires an RWST Channel Calibration of the alarm transmitter every 18 months and the indicating switch every 6 months.. ITS SR 3.3.3.2 maintains the requirement for periodic calibration of the alarm function at the CTS Frequency; however, the acceptance criteria is relocated to the FSAR (see ITS 3.3.3, DOC LA.4)

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated description and justification.

A.17 CTS 3.5.7 requires that the PAM instrumentation for each function in CTS Table 3.5-5 be Operable which includes a requirement for **CTS Table 3.5-5, Item 24, Core Exit Thermocouples**. **ITS LCO 3.3.3, Table 3.3.3-1, Functions 18, 19, 20, and 21, Core Exit Thermocouples**, maintain this requirement as follows:

a. CTS 3.5.7 requires that the instrumentation requirements in Table 3.5-5 be met when the reactor is not in the cold shutdown condition (i.e., Modes 1, 2, 3 and 4). ITS LCO 3.3.3 Applicability requires that the LCO 3.3.3 requirements be met in Modes 1, 2, and 3 only. This is a less restrictive change (see ITS 3.3.3, DOC L.1).

b. CTS Table 3.5-5 specifies that the number of channels available for this function is 4 detectors/quadrant and the minimum number of required channels 2 detectors/quadrant. ITS Table 3.3.3-1

maintains this requirement. Requirements for single failure tolerance and channel diversity are controlled administratively.

c. CTS Table 3.5-5 establishes an AOT of 7 days for PAM instrument channels (and 14 days for the associated recorder, see ITS 3.3.3, DOC LA.7) if one or both of the minimum required channels are not Operable (i.e., loss of function). ITS 3.3.3, Required Action A.1, maintains the 7 day AOT when one required channel of a PAM function is not Operable.

CTS Table 3.5-5 requires a plant shutdown if the requirements and/or Required Actions and Completion Times associated with the function are not met. ITS 3.3.3, Required Actions C.1 and C.2 maintain this requirement; however the Completion Times for the shutdown in ITS 3.3.3 are more restrictive (see ITS 3.3.3, DOC M.4). CTS Table 3.5-5 requires the plant be placed in cold shutdown when requirements are not met. ITS 3.3.3, Required Action C.2, requires that the plant be placed in Mode 4 when requirements are not met which is consistent with the change in Applicability for PAM instrumentation (See ITS 3.3.3, DOC L.1).

d. CTS Table 4.1-1, Item 37, requires a Core Exit Thermocouple Channel Check every 24 hours and a Channel Calibration every 24 months. ITS SR 3.3.3.1 and SR 3.3.3.2 maintain these requirements; however, ITS SR 3.3.3.1 reduces the frequency for the Channel Check to once per 31 days. This reduction in the required Frequency for a Channel Check is a less restrictive change (see ITS 3.3.3, DOC L.2).

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated description and justification.

A.18 CTS 3.5.2 requires that the instrumentation for each function in CTS Table 3.5-4 be Operable which includes a requirement for **CTS Table 3.5-4, Item 6, Main Steam Line Radiation Monitors.** ITS **LCO 3.3.3, Table 3.3.3-1, Function 22, Main Steam Line Radiation**, maintains this requirement as follows:

a. CTS Table 3.5-4, Note 3, specifies that the actions for inoperable Main Steam Line (MSL) Radiation Monitors must be implemented when the reactor is not in the cold shutdown condition (i.e., Modes 1, 2, 3 and 4). This Action implicitly establishes an applicability of Modes 1, 2, 3 and 4. ITS LCO 3.3.3 Applicability requires that the LCO 3.3.3 requirements be met in Modes 1, 2, and 3 only. This is a less restrictive change (see ITS 3.3.3, DOC L.1).

b. CTS Table 3.5-4, Item 6, MSL Radiation Monitors, specifies that the number of channels available for this function is 1 per steam line and requires Operability of 1 channel/steam generator. LCO 3.3.3, Table 3.3.3-1, Function 22, MSL Radiation, maintains this requirement for 1 channel/steam line.

c. CTS Table 3.3-4, Note 3, requires initiation of alternate monitoring capability within 6 days if one or more MSL radiation monitor(s) are inoperable. This requirement is not retained in Technical Specifications (See ITS 3.3.3, DOC LA.6). Additionally, CTS Table 3.3-4, Note 3, requires that if one or more MSL radiation monitor(s) are inoperable, then a special report to the NRC explaining the preplanned alternate method of monitoring, the cause of the inoperability, and the plans and schedule for restoration must be submitted within 14 days of expiration of the 7 day AOT. ITS 3.3.3, Required Action A.1, maintains the 7 day AOT when one required channel of a PAM function is not Operable and ITS 3.3.3, Required Action D.1, maintains the requirement to submit a special report to the NRC within the following 7 days if one or more MSL radiation monitors is inoperable beyond the 7 day AOT.

d. CTS Table 4.1-1, Item 15.e, requires an MSL Radiation Monitor Channel Check every 24 hours and a Channel Calibration every 24 months. ITS SR 3.3.3.1 and SR 3.3.3.2 maintain these requirements; however, ITS SR 3.3.3.1 reduces the frequency for the Channel Check to once per 31 days. This reduction in the required Frequency for a Channel Check is a less restrictive change (see ITS 3.3.3, DOC L.2)

Each of the changes described above is an administrative change with no

adverse impact on safety except as noted with a cross reference to the associated description and justification.

A.19 CTS 3.5 does not include any PAM or LCO requirements for the Gross Failed Fuel Detectors; however, CTS Table 4.1-1, Item 15.f, specifies surveillance requirements for the Gross Failed Fuel Detectors. This is an implicit requirement for the Operability the Gross Failed Fuel Detectors consistent with Safety Evaluation: Conformance to Regulatory Guide 1.97, Revision 3, for Indian Point 3 (TAC No. 51099), dated April 3, 1991, which identifies this function as a Type A variable provided to allow determination of reactor coolant system radioactivity concentration.

a. CTS 3.5 does not establish any Applicability requirements for the Gross Failed Fuel Detectors although these detectors are required. ITS LCO 3.3.3, Applicability, requires that the LCO 3.3.3 requirements be met in Modes 1, 2, and 3. This is an administrative change with no adverse impact on safety because it is a reasonable interpretation of the equivalent CTS requirement.

b. CTS 3.5 does not establish any requirements for the number of Operable channels of the Gross Failed Fuel Detectors although these detectors are required. ITS Table 3.3.3-1, Function 23, establishes a requirement for the Operability of 1 of the two available Gross Failed Fuel Detectors. This is an administrative change with no adverse impact on safety.

c. CTS 3.5 does not establish any AOT or compensatory actions if one or both channels of the Gross Failed Fuel Detectors inoperable. ITS 3.3.3, Required Action A.1, establishes a 7 day AOT when the one required channel of this function is not Operable. Additionally, ITS 3.3.3, Required Action D.1, establishes a requirement to submit a special report to the NRC within the following 7 days if one or more MSL radiation monitors is inoperable beyond the 7 day AOT. This is an administrative change with no adverse impact on safety because the requirement to submit a report to the NRC is an administrative requirement and there is no change to the existing technical requirements.

d. CTS Table 4.1-1, Item 15.f, requires a Gross Failed Fuel Detector Channel Check every 24 hours and a Channel Calibration every 24 months. ITS SR 3.3.3.1 and SR 3.3.3.2 maintain these requirements; however, ITS SR 3.3.3.1 reduces the frequency for the Channel Check to once per 31 days. This reduction in the required Frequency for a Channel Check is a less restrictive change (see ITS 3.3.3, DOC L.2)

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated description and justification.

A.20 CTS 3.5.7 requires that the PAM instrumentation for each function in CTS Table 3.5-5 be Operable which includes a requirement for **CTS Table 3.5-5, Item 15, RCS Subcooling Margin Monitor**. ITS **LCO 3.3.3**, Table 3.3.3-1, Function 23, RCS Subcooling Margin, maintains this requirement as follows:

a. CTS 3.5.7 requires that the instrumentation requirement in Table 3.5-5 be met when the reactor is not in the cold shutdown condition (i.e., Modes 1, 2, 3 and 4). ITS LCO 3.3.3 Applicability requires that the LCO 3.3.3 requirements be met in Modes 1, 2, and 3 only. This is a less restrictive change (see ITS 3.3.3, DOC L.1).

b. CTS Table 3.5-5 specifies that the number of channels available for this function is 1 and the minimum number of required channels is 1. ITS Table 3.3.3-1 maintains this requirement. Requirements for single failure tolerance and channel diversity are controlled administratively. The ITS Bases are revised to indicate that two channels of this function are available.

c. ITS 3.3.3, Required Action A.1, maintains the 7 day AOT when one required channel of a PAM function is not Operable and ITS 3.3.3, Required Action D.1, maintains the requirement to submit a special report to the NRC within the following 7 days if one or more channels is inoperable beyond the 7 day AOT.

d. CTS Table 4.1-1, Item 29, requires a Channel Check every 24 hours and a Channel Calibration every 24 months for CTS Item 15, RCS Subcooling Margin Monitor. ITS SR 3.3.3.1 and SR 3.3.3.2 maintain these requirements; however, ITS SR 3.3.3.1 reduces the frequency for the Channel Check to once per 31 days. This reduction in the required Frequency for a Channel Check is a less restrictive change (see ITS 3.3.3, DOC L.2).

Each of the changes described above is an administrative change with no adverse impact on safety except as noted with a cross reference to the associated description and justification.

A.21 The Actions for ITS 3.3.3, Post Accident Monitoring (PAM) Instrumentation, are preceded by a Note that specifies: "Separate Condition entry is allowed for each channel." This allowance provides explicit recognition that the ITS is designed to allow completely separate re-entry into any Condition for each train and/or channel addressed by the Condition. This includes separate tracking of Completion Times based on this re-entry. This allowance is consistent with an unstated assumption in the CTS. Therefore, the addition of this Note is an administrative change with no impact on safety.

A.22 ITS LCO 3.4.15, Actions Note, is added to provide an allowance that ITS LCO 3.0.4 is not applicable to Post Accident Monitoring (PAM) Instrumentation. This allowance is needed because it permits entry into Modes 1, 2 and 3 if one or more PAM instruments are inoperable as long as the Required Actions and associated Completion Times are met for any applicable Condition. This change is acceptable because ITS LCO 3.3.3 Required Actions permit operation to continue anywhere from 30 days to indefinitely when one or more PAM instruments are inoperable as long as the compensatory Required Actions are performed. This is an administrative change with no impact on safety because there is no equivalent to LCO 3.0.4 in the CTS; therefore, providing an exception results in no changes to the existing requirements. The justification for adding LCO 3.0.4 is addressed in Discussion of Changes for ITS Section 1.0.

MORE RESTRICTIVE

M.1 ITS LCO 3.3.3, Table 3.3.3-1, Function 1, Nuclear Flux, is added to Technical Specifications because neutron flux was identified as a Regulatory Guide 1.97, Type A variable, i.e, it provides primary information needed to permit operating personnel to take the specified manually controlled actions for which no automatic control is provided and that are required for safety systems to accomplish their safety functions for design basis accident events. ITS LCO 3.3.3, Table 3.3.3-1, Function 1, requires Operability in Modes 1, 2, and 3 of one of the two available channels of nuclear flux indication that covers the full range of flux that may occur post accident. To satisfy this requirement, either of the two channels of the Excore Neutron Flux Detection System using detectors N38 or N39 may be used to provide neutron flux indication from the source range to 100% RTP. The Excore Neutron Flux Detection System is an indication only system that displays on the QSPDS in the Control Room.

In conjunction with this change, Required Action A.1 was established to require restoration within 7 days if the one required channel of this Function is not Operable. Otherwise, ITS Specification 5.6.7 requires a special report to the NRC that outlines the preplanned alternate method of monitoring, the cause of the inoperability, and the plans and schedule for restoring the instrumentation channels of the Function to OPERABLE status. The allowable out of service times are acceptable because the NIS source, intermediate and power range instruments provide redundance for this function.

ITS SR 3.3.3.1 and SR 3.3.3.2 are added for this function to perform a Channel Check to verify that a gross instrumentation failure has not occurred and for periodic calibration, respectively.

These more restrictive changes are acceptable because they do not introduce any operation which is unanalyzed while providing greater assurance that this post accident monitoring instrumentation will be Operable when required. Therefore, this change has no adverse impact on safety.

M.2 ITS LCO 3.3.3, Table 3.3.3-1, Function 9, Containment Isolation Valve Position, is added to provide verification of containment Operability, and Phase A and B isolation. This function is added to Technical Specifications because Containment Isolation Valve Position was identified as a Regulatory Guide 1.97, Type A variable, i.e, it provides primary information needed to permit operating personnel to take the specified manually controlled actions for which no automatic control is provided and that are required for safety systems to accomplish their safety functions for design basis accident events. There are no equivalent requirements in the CTS.

This requirement is applicable in Modes 1, 2, and 3. One of the two channels of closed indication is required for each containment penetration with two isolation valves and one channel is required for penetrations with only one installed channel. This requirement does not apply to isolation valves whose associated penetration is isolated by at least one closed and deactivated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured.

In conjunction with this change, Conditions and Required Actions are added to establish a 7 day AOT when the required channel is. Failure to restore indication requirements for any penetration within the AOT requires issuing a special report to the NRC explaining the preplanned alternate method of monitoring, the cause of the inoperability, and the plans and schedule for restoration.

ITS SR 3.3.3.1 and SR 3.3.3.2 are added for this function to perform a Channel Check every 31 days for each required instrumentation channel that is normally energized to verify that a gross instrumentation failure has not occurred, and to perform a Channel Calibration every 24 months. There are no equivalent requirements in the CTS. These more restrictive changes are acceptable because they do not introduce any operation which is unanalyzed while requiring more conservative requirements for post accident monitoring instrumentation than are currently required. Therefore, this change has no adverse impact on safety.

M.3 ITS LCO 3.3.3, Table 3.3.3-1, Function 16, Condensate Storage Tank

Level, is added to provide the ability to monitor the status of the water supply to the auxiliary feedwater pumps. This function is added to Technical Specifications because Condensate Storage Tank Level was identified as a Regulatory Guide 1.97, Type A variable, i.e, it provides primary information needed to permit operating personnel to take the specified manually controlled actions for which no automatic control is provided and that are required for safety systems to accomplish their safety functions for design basis accident events. There are no equivalent requirements in the CTS.

This requirement is applicable in Modes 1, 2, and 3. Requiring Operability of 1 of the two available 2 channels of CST level indication provides the necessary indication. Diverse indication of CST level can be derived from auxiliary feedwater suction pressure indication.

In conjunction with this change, Conditions and Required Actions are added to establish a 7 day AOT when the required channel is. Failure to restore indication requirements for any penetration within the AOT requires issuing a special report to the NRC explaining the preplanned alternate method of monitoring, the cause of the inoperability, and the plans and schedule for restoration.

ITS SR 3.3.3.1 and SR 3.3.3.2 are added for this function to perform a Channel Check every 31 days for each required instrumentation channel that is normally energized to verify that a gross instrumentation failure has not occurred, and to perform a Channel Calibration every 24 months.

These more restrictive changes are acceptable because they do not introduce any operation which is unanalyzed while requiring more conservative requirements for post accident monitoring instrumentation than are currently required. Therefore, this change has no adverse impact on safety.

M.4 CTS 3.3.A.5 establishes the reactor shutdown requirements if the RWST level alarm requirements are not restored to meet CTS requirements within specified AOT. CTS 3.5-5 (sheet 3 of 3) establishes the reactor shutdown requirements if Table 3.5-5 PAM instruments are not restored to

meet CTS requirements within specified AOT. Both of these CTS shutdown requirements specify that, if the reactor is critical when requirements are not met, then the reactor must be in hot shutdown (Mode 3) within 4 hours and cold shutdown (Mode 5) within the following 24 hours. However, if the reactor is subcritical when requirements are not met, CTS 3.3.A.5.b requires only that RCS temperature and pressure not be increased more than 25°F and 100 psi, respectively, over existing values with the requirement to proceed to cold shutdown (Mode 5) deferred by 48 hours.

Under the same conditions, ITS 3.3.3, Required Actions C.1 and C.2, require that the reactor be in Mode 3 in 6 hours and Mode 4 in 12 hours (see ITS 3.3.3, DOC L.1) regardless of the status of the unit when the Condition is identified. The allowances provided in CTS 3.3.A.5.b and CTS 3.5-5 (sheet 3 of 3, Notes 2 and 3) are deleted.

This change is needed to eliminate the ambiguity created by CTS 3.3.A.5.b and CTS 3.5-5 (sheet 3 of 3, Notes 2 and 3) when performing a reactor shutdown and cooldown are required and to ensure that the plant is placed outside the LCO Applicability promptly when the LCO requirements are not met. This change is acceptable because placing the plant outside the LCO Applicability when LCO requirements are not met is conservative and there is no change in the CTS 3.3.A.5 and CTS 3.5-5 (sheet 3 of 3, Note 1) requirements. This change has no significant adverse impact on safety.

M.5 For CTS Table 3.5-5, Item 12, Containment Recirculation Sump Water Level (Narrow Range), CTS Table 3.5-5, Note +, establishes an AOT of 30 days for loss of containment sump narrow range indication (i.e. both the Recirculation sump narrow range and the containment sump narrow range). ITS 3.3.3, Required Action A.1, establishes a 7 day AOT when all required channels of containment sump narrow range indication function are not Operable.

This change is needed because CTS CTS Table 3.5-5 requires the Operability of both Item 12, Containment Recirculation Sump Water Level (Narrow Range), and Item 11, Containment Sump Water Level (Narrow Range); whereas, ITS LCO 3.3.3 requires Operability of the Type A PAM

instruments and only Containment Recirculation Sump Water Level (Narrow Range) meets this requirement (See ITS 3.3.3, DOC LA.1). This more restrictive change is acceptable because it does not introduce any operation which is unanalyzed while greater assurance that at least one channel of Containment Recirculation Sump Water Level (Narrow Range) will be available when required. Therefore, this change has no adverse impact on safety.

M.6 CTS Table 4.1-1 does not identify an explicit requirement for periodic testing of the RCS Pressure instrument required by CTS Table 3.5-5, Item 8. ITS SR 3.3.3.1 and SR 3.3.3.2 are added to require a Channel Check every 31 days a Channel Calibration every 24 months.

CTS Table 4.1-1 does not identify an explicit requirement for periodic testing of the RCS hot leg and cold leg wide range temperature instruments required by CTS Table 3.5-5, Item 10, Hot Leg Temperature (Th) (Wide Range) and CTS Table 3.5-5, Item 9, Cold Leg Temperature (Tc) (Wide Range). ITS SR 3.3.3.1 and SR 3.3.3.2 are added to require a Channel Check every 31 days a Channel Calibration every 24 months.

CTS Table 4.1-1, Item 16.b and 16.c, require that CTS Table 3.5-5, Item 12, Containment Recirculation Sump Water Level (Narrow Range), and CTS Table 3.5-5, Item 21, Containment Water Level (Wide Range), are calibrated every 24 months. However, there is no CTS requirement for periodic Channel Checks of these functions, probably because there is no indicated level during normal operation. There is ITS SR 3.3.3.1 establishes a new requirement to perform a Channel Check of these function every 31 days to ensure that there is no indication of channel failure.

These more restrictive changes are acceptable because they do not introduce any operation which is unanalyzed while requiring periodic verification of the Operability of PAM instruments required by ITS LCO 3.3.3. Therefore, this change has no adverse impact on safety.

M.7 CTS Table 3.5-5 specifies that the number of channels available for CTS Table 3.5-5, Item 24, Core Exit Thermocouples, is 4 detectors/quadrant

and the minimum number of required channels 2 detectors/quadrant. ITS Table 3.3.3-1 establishes a new requirement for redundancy for this function by requiring Operability of 3 core exit thermocouples/quadrant. Requiring 3 channels per core quadrant ensures that at least 2 channels will be available in each of the 4 quadrants following a single failure. This will ensure sufficient channels are available to be indicative of the core radial temperature gradient.

LESS RESTRICTIVE

L.1 CTS 3.5.7 specifies that CTS Table 3.5-5 requirements for PAM instrumentation be met when the reactor is not in the cold shutdown condition (i.e. Modes 1, 2, 3, and 4). ITS LCO 3.3.3, Applicability, specifies that LCO requirements for PAM instrumentation be met in Modes 1, 2, and 3. This change is acceptable because PAM instrumentation requirements are established to ensure Operability of these variables needed for the diagnosis and initiation of preplanned actions required to mitigate design basis accidents (DBA). IP3 safety analyses assume that plant conditions needed for the initiation of a DBA exist only when the plant is in Modes 1, 2, or 3. In Modes 4, 5, and 6, plant 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. This change does not have a significant adverse impact on safety because there is a very low probability that this change will result in PAM instrumentation not being available when needed for the diagnosis and initiation of preplanned actions required to mitigate a DBA.

L.2 CTS Table 4.1-1, establishes requirements for periodic Channel Checks for instrument channels including the reactor protection system, Engineered Safety Feature Actuation System (ESFAS) Instrumentation, Post Accident Monitoring (PAM) Instrumentation. To satisfy Operability verification requirements for RPS and ESFAS, Channels checks are typically performed every 12 hours. ITS SR 3.3.1.1 and IS SR 3.3.2.1 will continue to maintain the 12 hour Frequency for RPS and ESFAS instruments, respectively, even if the instrument is also required by ITS LCO 3.3.3. ITS LCO 3.3.3.1 establishes a 31 day SR Frequency for

Channel Checks for all PAM instrumentation. This is a less restrictive change for those PAM instruments that are not also RPS and ESFAS channels.

This change in surveillance frequencies is acceptable because of the following: these instruments are used for post accident monitoring only and are not relied upon to initiate any required automatic action; the LCO requirements for each of these instruments requires sufficient redundancy to support a random single failure; and, each instrument channel function is supplemented by diverse alternate indication. Additionally, the Frequency of 31 days for the Channel Check is consistent with operating experience that indicating that channel failure is rare. Finally, the Channel Checks supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with these functions. This change does not have a significant adverse impact on safety.

REMOVED DETAIL

LA.1 CTS 3.5.7 and CTS Table 3.5-5 requires the Operability of "Indicators and Recorders Available to the Operators" and predates the requirements established Regulator Guide 1.97, Instrumentation For Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident. However, the requirements are generally consistent with subsequent commitments and requirements for RG 1.97 instrumentation. Therefore, CTS Table 3.5-5 was used as the starting point for the development of ITS LCO 3.3.3, PAM Instrumentation, which establishes LCO requirements for all RG 1.97, Type A instruments, and all RG 1.97, Category I, non-Type A instruments. In conjunction with this change, requirements in CTS Table 3.5-5 (and associated surveillance requirements in CTS Table 4.1-1) for the following alarm and/or indication instruments that are not RG 1.97, Type A or Category I are relocated to the FSAR and plant procedures.

1.a. Containment Pressure (narrow range)
7. RHR Recirculation Flow
11. Containment Sump Water level (Narrow Range, Analog)
13. Temperature Sensors in:

a. Piping Penetration Area
b. Mini-Containment Area
c. Steam Gen. Blowdown Heat Exchanger Room
d. Auxiliary Boiler Feedwater Pump Bldg.

14. Level Sensors in Lower Level of Turbine Building
16. PORV Position Indicator (Acoustic Monitor)
17. PORV Position Indicator (Limit Switch)
18. PORV Block Valve Position Indicator (Limit Switch)
19. Safety Valve Position Indicator (Acoustic Monitor)
20. Auxiliary Feedwater Flow Rate

This change, which allows indications and alarms that are not RG 1.97, Type A or Category I, to be maintained in the FSAR and implemented by procedures, is acceptable because the requirements of 10 CFR 50.59, Changes, Tests and Experiments, are designed to assure that changes to the FSAR do not result in changes to the Technical Specification requirements and do not result in significant increases in the probability or consequences of accidents previously evaluated, do not create the possibility of a new or different kind of accident, and do not result in a significant reduction in a margin of safety. Additionally, IP3 programs that implement FSAR changes in accordance with 10 CFR 50.59 require periodic submittal of FSAR and Bases changes to the NRC for review.

This change is a less restrictive administrative change with no impact on safety because an appropriate change control process and an appropriate level of regulatory oversight are maintained for the information being relocated out of the Technical Specifications.

LA.2 CTS Table 3.5-5 includes design information about RG 1.97, Type A instruments, and RG 1.97, Category I, non-Type A, such as number of channels available and availability of recorders. This information is not required to specify the requirements of ITS LCO 3.3.3; therefore, this information is relocated to the FSAR.

This change, which allows design information related to RG 1.97, Type A and Category I instruments to be maintained in the FSAR, is acceptable because the requirements of 10 CFR 50.59, Changes, Tests and

Experiments, are designed to assure that changes to the FSAR do not result in changes to the Technical Specification requirements and do not result in significant increases in the probability or consequences of accidents previously evaluated, do not create the possibility of a new or different kind of accident, and do not result in a significant reduction in a margin of safety. Additionally, IP3 programs that implement FSAR changes in accordance with 10 CFR 50.59 require periodic submittal of FSAR and Bases changes to the NRC for review.

This change is a less restrictive administrative change with no impact on safety because an appropriate change control process and an appropriate level of regulatory oversight are maintained for the information being relocated out of the Technical Specifications

LA.3 CTS Table 3.5-5 requires the Operability of "Indicators and Recorders Available to the Operators." CTS 4.1-1 specifies the surveillance requirements for these instruments. ITS SR 3.3.3.1 and ITS SR 3.3.3.2 maintain the requirements for Channels Checks and Calibrations of these instruments; however, the quarterly Channel Operational Test of the associated alarms is not included in the ITS and is relocated to the FSAR and plant procedures.

This change, which allows functional tests of alarms associated with RG 1.97 instruments to be maintained in the FSAR and implemented by procedures, is acceptable because the requirements of 10 CFR 50.59, Changes, Tests and Experiments, are designed to assure that changes to the FSAR do not result in changes to the Technical Specification requirements and do not result in significant increases in the probability or consequences of accidents previously evaluated, do not create the possibility of a new or different kind of accident, and do not result in a significant reduction in a margin of safety. Additionally, IP3 programs that implement FSAR changes in accordance with 10 CFR 50.59 require periodic submittal of FSAR and Bases changes to the NRC for review.

This change is a less restrictive administrative change with no impact on safety because an appropriate change control process and an appropriate level of regulatory oversight are maintained for the

information being relocated out of the Technical Specifications.

LA.4 CTS 3.3.A.3.k requires that the refueling water storage tank (RWST) low level alarms are operable and set to alarm between 10.5 feet and 12.5 feet of water in the tank and CTS Table 4.1-1, Item 13, requires an RWST Channel Calibration of the transmitter every 18 months and the indicating switch every 6 months. ITS SR 3.3.3.2 maintains the requirement for periodic calibration of the alarm function at the CTS Frequency; however, the acceptance criteria is relocated to the FSAR and implemented by plant procedures. This change is acceptable because RWST is an alarm only function that (in conjunction with containment sump level indication) alerts operators to manually switch from the safety injection mode to the Recirculation mode of operation.

This change, which allows acceptance criteria for the RWST low level alarm to be maintained in the FSAR and implemented by procedures, is acceptable because the requirements of 10 CFR 50.59, Changes, Tests and Experiments, are designed to assure that changes to the FSAR do not result in changes to the Technical Specification requirements and do not result in significant increases in the probability or consequences of accidents previously evaluated, do not create the possibility of a new or different kind of accident, and do not result in a significant reduction in a margin of safety. Additionally, IP3 programs that implement FSAR changes in accordance with 10 CFR 50.59 require periodic submittal of FSAR and Bases changes to the NRC for review.

This change is a less restrictive administrative change with no impact on safety because an appropriate change control process and an appropriate level of regulatory oversight are maintained for the information being relocated out of the Technical Specifications.

LA.5 CTS 3.3.A.1.b requires that one channel of the refueling water storage tank (RWST) low level alarms is Operable in Mode 4. (The Mode 4 Applicability is implicit because CTS 3.3.A.3.k requires two Operable channels in Modes 1, 2 and 3.) The requirement for one Operable RWST low level alarm channel in Mode 4 is not included in ITS 3.3.3 and is relocated to the FSAR and implemented by plant procedures. This change

is acceptable because RG 1.97 instruments are required in Modes 1, 2 and 3 only (See ITS 3.3.3, DOC L.1).

This change, which allows RWST low level alarm requirements in Mode 4 to be maintained in the FSAR and implemented by procedures, is acceptable because the requirements of 10 CFR 50.59, Changes, Tests and Experiments, are designed to assure that changes to the FSAR do not result in changes to the Technical Specification requirements and do not result in significant increases in the probability or consequences of accidents previously evaluated, do not create the possibility of a new or different kind of accident, and do not result in a significant reduction in a margin of safety. Additionally, IP3 programs that implement FSAR changes in accordance with 10 CFR 50.59 require periodic submittal of FSAR and Bases changes to the NRC for review.

This change is a less restrictive administrative change with no impact on safety because an appropriate change control process and an appropriate level of regulatory oversight are maintained for the information being relocated out of the Technical Specifications.

LA.6 CTS Table 3.5-5, in addition to establishing an AOT, requires initiation of alternate monitoring capability within 72 hours if the one required channel of the Containment Area Radiation function is not Operable (i.e., loss of function). Likewise, CTS Table 3.5-4, Note 3, requires initiation of alternate monitoring capability within 6 days if one or more MSL radiation monitor(s) are inoperable. ITS LCO 3.3.3 maintains the AOTs for the Containment Area Radiation PAM function and MSL radiation monitor PAM function (except as identified and justified in ITS 3.3.3, DOCs A.10 and A.22). Additionally, ITS LCO 3.3.3 and Specification 5.6.7 maintain the requirement to implement the preplanned alternate method of monitoring. However, the time limits for implementing alternate monitoring are relocated to the FSAR and will be implemented by plant procedures.

This change is acceptable because the requirements of 10 CFR 50.59, Changes, Tests and Experiments, are designed to assure that changes to the FSAR do not result in changes to the Technical Specification requirements and do not result in significant increases in the

probability or consequences of accidents previously evaluated, do not create the possibility of a new or different kind of accident, and do not result in a significant reduction in a margin of safety. Additionally, IP3 programs that implement FSAR changes in accordance with 10 CFR 50.59 require periodic submittal of FSAR and Bases changes to the NRC for review.

This change is a less restrictive administrative change with no impact on safety because an appropriate change control process and an appropriate level of regulatory oversight are maintained for the information being relocated out of the Technical Specifications.

LA.7 CTS Table 3.5-5, Note **, establishes a 7 day AOT for the loss of a PAM instrument channel; however, CTS Table 3.5-5, Note **, establishes a 14 day AOT for the loss of the associated recorder, if applicable. ITS 3.3.3, Required Actions, maintain the 7 day AOT for the loss of a PAM instrument indication channel (i.e., loss of function); however, ITS 3.3.3 does not establish any restrictions when the channel indication is Operable but the associated recorder, which may be required by RG 1.97, is not Operable. AOTs for the PAM instrument recorder capability are relocated to the FSAR and implemented by plant procedures. This change is acceptable because the recorder function is not an integral requirement for a RG 1.97 Type A instrument.

This change is acceptable because the requirements of 10 CFR 50.59, Changes, Tests and Experiments, are designed to assure that changes to the FSAR do not result in changes to the Technical Specification requirements and do not result in significant increases in the probability or consequences of accidents previously evaluated, do not create the possibility of a new or different kind of accident, and do not result in a significant reduction in a margin of safety. Additionally, IP3 programs that implement FSAR changes in accordance with 10 CFR 50.59 require periodic submittal of FSAR and Bases changes to the NRC for review.

This change is a less restrictive administrative change with no impact on safety because an appropriate change control process and an appropriate level of regulatory oversight are maintained for the

information being relocated out of the Technical Specifications.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.3:
"Post Accident Monitoring (PAM) Instrumentation"

PART 4:

No Significant Hazards Considerations
for
Changes between CTS and ITS
that are
Less Restrictive

No Significant Hazard Considerations for Changes that are Administrative, More Restrictive, and Removed Details are the same for all Packages. A Copy is included at the end of the Package.

NO SIGNIFICANT HAZARDS EVALUATION
ITS SECTION 3.3.3 - POST ACCIDENT MONITORING (PAM) INSTRUMENTATION

LESS RESTRICTIVE
("L.1" Labeled Comments/Discussions)

New York Power Authority has evaluated the proposed Technical Specification change identified as "Less Restrictive" in accordance with the criteria set forth in 10 CFR 50.92, and has determined that the proposed change does not involve a significant hazards consideration. The bases for the determination that the proposed change does not involve a significant hazards consideration are discussed below.

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

   This change revises the applicability of the PAM instrumentation requirements. CTS 3.5.7 requires that the instrumentation requirements in Table 3.3-5 be met when the reactor is not in the cold shutdown condition (i.e. Modes 1, 2, 3, and 4). ITS LCO 3.3.3 Applicability requires that the LCO 3.3.3 requirements be met in Modes 1, 2, and 3.

   This change will not result in a significant increase in the probability of an accident previously evaluated because the PAM instrumentation functions are related to the diagnosis and preplanned actions required to mitigate DBA's, and a change to the plant operating conditions in which the Pam instrumentation requirements are applicable would not increase the probability that an accident would occur.

   This change will not result in a significant increase in the consequences of an accident previously evaluated because PAM instrumentation will be Operable in Modes 1, 2 and 3. The applicable Design Basis Accidents (DBA's) for which PAM instrumentation is required 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. Therefore, there is a very low probability that this change will result in PAM instrumentation not being available when needed for the diagnosis and initiation of preplanned actions required to mitigate a DBA.

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

   The proposed change will not involve any physical changes to systems, structures, or components, or involve a change in normal plant operation. Therefore, it will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   This change does not involve a significant reduction in a margin of safety because it only affects the plant operating conditions for which the PAM instrumentation must be operable. The PAM instrumentation functions are related to the diagnosis and preplanned actions required to mitigate DBA's and are intended to assist the operators in minimizing the consequences of the accident. A change in the applicability of the requirements does not affect any margin of safety.

LESS RESTRICTIVE
("L.2" Labeled Comments/Discussions)

New York Power Authority has evaluated the proposed Technical Specification change identified as "Less Restrictive" in accordance with the criteria set forth in 10 CFR 50.92, and has determined that the proposed change does not involve a significant hazards consideration. The bases for the determination that the proposed change does not involve a significant hazards consideration are discussed below.

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

   ITS LCO 3.3.3.1 extends the nominal 12 hour Channel Check Frequency to a 31 day SR Frequency for all PAM instrumentation. This is a less restrictive change for those PAM instruments that are not also RPS and ESFAS instruments. ITS SR 3.3.1.1 and IS SR 3.3.2.1 will continue to maintain the 12 hour Frequency for RPS and ESFAS instruments,

respectively, even if the instrument is also required by ITS LCO 3.3.3.

This change will not result in a significant increase in the probability of an accident previously evaluated because PAM instrumentation functions are related to the diagnosis and preplanned actions required to mitigate DBA's, and a change to the plant operating condition the unit would be placed in if inoperable PAM instrumentation cannot be restored to an operable status within the required time period would not increase the probability that an accident would occur.

This change will not result in a significant increase in the consequences of an accident previously evaluated because of the following: these instruments are used for post accident monitoring only and are not relied upon to initiate any required automatic action; the LCO requirements for each of these instruments requires sufficient redundancy to support a random single failure; and, each instrument channel function is supplemented by diverse alternate indication. Additionally, the Frequency of 31 days for the Channel Check is consistent with operating experience that indicating that channel failure is rare. Finally, the Channel Checks supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with these functions. Therefore, there is a low probability that this change will result in PAM instrument channels not being available when required.

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

   The proposed change will not involve any physical changes to systems, structures, or components, or involve a change in normal plant operation. Therefore, it will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   This change does not involve a significant reduction in a margin of safety because of the following: these instruments are used for post accident monitoring only and are not relied upon to initiate any

required automatic action; the LCO requirements for each of these instruments requires sufficient redundancy to support a random single failure; and, each instrument channel function is supplemented by diverse alternate indication. Additionally, the Frequency of 31 days for the Channel Check is consistent with operating experience that indicating that channel failure is rare. Finally, the Channel Checks supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with these functions. Therefore, there is a low probability that this change will result in PAM instrument channels not being available when required.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.3:
"Post Accident Monitoring (PAM) Instrumentation"

PART 5:

NUREG-1431
Annotated to show differences between
NUREG-1431 and ITS

Status of NUREG 1431 Generic Changes for ITS 3.3.3

This ITS Specification is based on NUREG-1431 Specification No. **3.3.3**
as modified by the following Generic Changes:

OG No.	TSTF No.	Generic Change Description	NRC STATUS	IP3 STATUS	JD No.
BWROG-008 R3	**036 R3**	ADDITION OF LCO 3.0.3 N/A TO SHUTDOWN ELECTRICAL POWER SPECIFICATIONS	NRC Rejects: TSTF to Revise	Not Incorporated	**N/A**
CEOG-060		RELOCATION OF REMOTE SHUTDOWN SYSTEM	Rejected by TSTF	Not Incorporated	**N/A**
WOG-006	**019 R0**	RELOCATE THE DETAILS OF RTD AND THERMOCOUPLE CALIBRATION FROM THE CHANNEL CALIBRATION DEFINITION TO BASES OF INST. SPECS	NRC Review	Not Incorporated	**N/A**
WOG-024		REQUIRE OPERABLE DIVERSE PAM CHANNEL FOR 30 DAY COMPLETION TIME	Rejected by TSTF	Not Incorporated	**N/A**

3.3 INSTRUMENTATION

3.3.3 Post Accident Monitoring (PAM) Instrumentation

LCO 3.3.3 The PAM instrumentation for each Function in Table 3.3.3-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

----------NOTES----------

1. LCO 3.0.4 is not applicable.
2. Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one required channel inoperable.	A.1 Restore required channel to OPERABLE status.	30 days
B. Required Action and associated Completion Time of Condition A not met.	B.1 Initiate action in accordance with Specification 5.6.8.	Immediately
A C. ~~----------NOTE---------- Not applicable to hydrogen monitor channels. ----------~~ One or more Functions with two required channels inoperable.	A. C.1 Restore one channel to OPERABLE status.	7 days

CLB.1

CLB.1

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Two hydrogen monitor channels inoperable.	D.1 Restore one hydrogen monitor channel to OPERABLE status.	72 hours CLB.1
B ~~E~~. Required Action and associated Completion Time of Condition ~~C~~ A ~~or D~~ not met.	B ~~E~~.1 Enter the Condition referenced in Table 3.3.3-1 for the channel.	Immediately
C ~~F~~. As required by Required Action B ~~E~~.1 and referenced in Table 3.3.3-1.	C ~~F~~.1 Be in MODE 3. AND ~~F~~.2 C Be in MODE 4.	6 hours 12 hours
D ~~G~~. As required by Required Action B ~~E~~.1 and referenced in Table 3.3.3-1.	D ~~G~~.1 Initiate action in accordance with Specification 5.6 ~~8~~ 7.	Immediately

OR

One or more Functions with two or more required channels inoperable.

SURVEILLANCE REQUIREMENTS

----------NOTE----------
SR 3.3.3.1 and SR 3.3.3.2 apply to each PAM instrumentation Function in Table 3.3.3-1.

SURVEILLANCE		FREQUENCY
SR 3.3.3.1	Perform CHANNEL CHECK for each required instrumentation channel that is normally energized.	31 days
SR 3.3.3.2	----------NOTE---------- Neutron detectors are excluded from CHANNEL CALIBRATION. ---------- Perform CHANNEL CALIBRATION.	[18] months As Specified in Table 3.3.3-1.

SR 3.3.3.2 FREQUENCY

Table 3.3.3-1 (page 1 of 1)
Post Accident Monitoring Instrumentation

FUNCTION	REQUIRED CHANNELS	CONDITION REFERENCED FROM REQUIRED ACTION E.1 (B)
1. Power Range Neutron Flux	2	F
2. Source Range Neutron Flux	2	F
3. Reactor Coolant System (RCS) Hot Leg Temperature	2 per loop	F
4. RCS Cold Leg Temperature	2 per loop	F
5. RCS Pressure (Wide Range)	2	F
6. Reactor Vessel Water Level	2	G
7. Containment Sump Water Level (Wide Range)	2	F
8. Containment Pressure (Wide Range)	2	F
9. Containment Isolation Valve Position	2 per penetration flow path[a][b]	F
10. Containment Area Radiation (High Range)	2	G
11. Hydrogen Monitors	2	F
12. Pressurizer Level	2	F
13. Steam Generator Water Level (Wide Range)	2 per steam generator	F
14. Condensate Storage Tank Level	2	F
15. Core Exit Temperature – Quadrant [1]	2[c]	F
16. Core Exit Temperature – Quadrant [2]	2[c]	F
17. Core Exit Temperature – Quadrant [3]	2[c]	F
18. Core Exit Temperature – Quadrant [4]	2[c]	F
19. Auxiliary Feedwater Flow	2	F

Insert: 3.3-43-01

(a) Not required for isolation valves whose associated penetration is isolated by at least one closed and deactivated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured.

(b) Only one position indication channel is required for penetration flow paths with only one installed control room indication channel.

(c) A channel consists of two core exit thermocouples (CETs).

Reviewer's Note: Table 3.3.3-1 shall be amended for each unit as necessary to list:

(1) All Regulatory Guide 1.97, Type A instruments, and

(2) All Regulatory Guide 1.97, Category I, non-Type A instruments in accordance with the unit's Regulatory Guide 1.97, Safety Evaluation Report.

CLB.1

Insert: 3.3-43-02

INSERT: 3.3-43-01 (page 1 of 2)

<DOC A.3>	1.	Neutron Flux	1	D	24 months
<DOC A.4>	2.	RCS Hot Leg Temperature (wide range)	1 loop	C	24 months
	3.	RCS Cold Leg Temperature (wide range)	1 loop	C	24 months
<DOC A.5>	4.	RCS Pressure (wide Range)	1	C	24 months
<DOC A.6>	5.	Reactor Vessel Water Level	1	C	24 months
<DOC A.7>	6.	Containment Water Level (Wide Range)	1	C	24 months
	7.	Containment Water Level (Recirculation Sump)	1	C	24 months
<DOC A.8>	8.	Containment Pressure	1	C	18 months
<DOC A.9>	9.	Automatic Containment Isolation Valve Position	1 per penetration flow path[a]	D	24 months
<DOC A.10>	10.	Containment Area Radiation (High Range)	1	D	24 months
<DOC A.11>	11.	Containment Hydrogen Monitors	1[c]	C	92 days
<DOC A.12>	12.	Pressurizer Level	2	C	24 months
<DOC A.13>	13.	SG Water Level (Narrow Range)	2[b]	C	24 months
	14.	SG Water Level (Wide Range)	2[b]	C	24 months

INSERT: 3.3-43-01 (page 2 of 2)

(DOC A.14)	15.	Steam Generator Pressure	1 per steam generator	C	24 months
(DOC A.15)	16.	Condensate Storage Tank Level	1	D	24 months
(DOC A.16)	17.	RWST Level, Alarm	2	C	(d)
(DOC A.17)	18.	Core Exit Thermocouples-Quadrant 1	2	C	24 months
	19.	Core Exit Thermocouples-Quadrant 2	2	C	24 months
	20.	Core Exit Thermocouples-Quadrant 3	2	C	24 months
	21.	Core Exit Thermocouples-Quadrant 4	2	C	24 months
(DOC A.18)	22.	Main Steam Line Radiation	1 per steam line	~~C~~ D	24 months
(DOC A.19)	23.	Gross Failed Fuel Detector	1	D	24 months
(DOC A.20)	24.	RCS Subcooling Margin	1	C	24 months

INSERT: 3.3-43-02

(b) Two of the four steam generators must have one OPERABLE wide range level channel and the remaining two steam generators must each have one OPERABLE level channel which may be either wide range or narrow range.

(c) Hydrogen monitor OPERABILITY requires that the associated containment fan cooler unit is OPERABLE.

(d) 18 months for RWST level alarm transmitters and 6 months for RWST alarm switches.

B 3.3 INSTRUMENTATION

B 3.3.3 Post Accident Monitoring (PAM) Instrumentation

BASES

BACKGROUND

The primary purpose of the PAM instrumentation is to display unit variables that provide information required by the control room operators during accident situations. This information provides the necessary support for the operator to take the manual actions for which no automatic control is provided and that are required for safety systems to accomplish their safety functions for Design Basis Accidents (DBAs).

The OPERABILITY of the accident monitoring instrumentation ensures that there is sufficient information available on selected unit parameters to monitor and to assess unit status and behavior following an accident.

The availability of accident monitoring instrumentation is important so that responses to corrective actions can be observed and the need for, and magnitude of, further actions can be determined. These ~~essential~~ instruments are identified by unit specific documents (Ref. 1) addressing the recommendations of Regulatory Guide 1.97 (Ref. 2) as required by Supplement 1 to NUREG-0737 (Ref. 3).

The instruments governed by the LCO are the

The instrument channels required to be OPERABLE by this LCO include two classes of parameters identified during unit specific implementation of Regulatory Guide 1.97 ~~as~~ Type A and Category I variables.

which are defined as follows:

Type A variables are included in this LCO because they provide the primary information required for the control room operator to take specific manually controlled actions for which no automatic control is provided, and that are required for safety systems to accomplish their safety functions for DBAs. ~~Because the list of Type A variables differs widely between units, Table 3.3.3-1 in the accompanying LCO contains no examples of Type A variables, except for those that may also be Category I variables.~~ PA.1

Category I variables are the key variables deemed risk significant because they are needed to:

(continued)

BASES

BACKGROUND (continued)

- Determine whether other systems important to safety are performing their intended functions;
- Provide information to the operators that will enable them to determine the likelihood of a gross breach of the barriers to radioactivity release; and
- Provide information regarding the release of radioactive materials to allow for early indication of the need to initiate action necessary to protect the public, and to estimate the magnitude of any impending threat.

These key variables are identified by the unit specific Regulatory Guide 1.97 analyses (Ref. 1). These analyses identify the unit specific Type A and Category I variables and provide justification for deviating from the NRC proposed list of Category I variables.

~~Reviewer's Note: Table 3.3.3-1 provides a list of variables typical of those identified by the unit specific Regulatory Guide 1.97 analyses. Table 3.3.3-1 in unit specific Technical Specifications (TS) shall list all Type A and Category I variables identified by the unit specific Regulatory Guide 1.97 analyses, as amended by the NRC's Safety Evaluation Report (SER).~~

The specific instrument Functions listed in Table 3.3.3-1 are discussed in the LCO section.

APPLICABLE SAFETY ANALYSES

The PAM instrumentation ensures the operability of Regulatory Guide 1.97 Type A and Category I variables so that the control room operating staff can:

- Perform the diagnosis specified in the emergency operating procedures (these variables are restricted to preplanned actions for the primary success path of DBAs), e.g., loss of coolant accident (LOCA);
- Take the specified, pre-planned, manually controlled actions, for which no automatic control is provided, and that are required for safety systems to accomplish their safety function;

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

- Determine whether systems important to safety are performing their intended functions;
- Determine the likelihood of a gross breach of the barriers to radioactivity release;
- Determine if a gross breach of a barrier has occurred; and
- Initiate action necessary to protect the public and to estimate the magnitude of any impending threat.

PAM instrumentation that meets the definition of Type A in Regulatory Guide 1.97 satisfies Criterion 3 of ~~the NRC~~ ~~Policy Statement~~ 10 CFR 50.36. 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. and, therefore, meet Criterion 4 of 10 CFR 50.36 PA.1

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~~ provides ~~sufficient~~ information ~~available on~~ about selected unit parameters to monitor and assess unit status following an accident. This capability is consistent with the recommendations of Reference 1. CLB.1

Insert: B 3.3-123-01

~~LCO 3.3.3 requires two OPERABLE channels for most Functions. 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.~~ CLB.1

(continued)

NUREG-1431 Markup Inserts
ITS SECTION 3.3.3 - POST ACCIDENT MONITORING (PAM) INSTRUMENTATION

INSERT: B 3.3-123-01

This LCO requires OPERABILITY of only one channel of each Type A and Category I variable. The additional channels of each Type A and Category I instrument described in Reference 1 and needed to meet Reference 2 requirements for single failure tolerance and channel diversity are controlled administratively.

BASES

LCO (continued)

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 at some units if the unit specific Regulatory Guide 1.97 analyses (Ref. 1) 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.

The exception to the two channel requirement is Containment Isolation Valve (CIV) Position. In this case, the important information is the status of the containment penetrations. The LCO requires one position indicator for each active CIV. This is sufficient to redundantly verify the isolation status of each isolable penetration either via indicated status of the active valve and prior knowledge of a passive valve, or via system boundary status. If a normally active CIV is known to be closed and deactivated, position indication is not needed to determine status. Therefore, the position indication for valves in this state is not required to be OPERABLE. CLB.1

Table 3.3.3-1 provides a list of variables typical of those identified by the unit specific Regulatory Guide 1.97 (Ref. 1) analyses. Table 3.3.3-1 in unit specific TS should list all Type A and Category I variables identified by the unit specific Regulatory Guide 1.97 analyses, as amended by the NRC's SER. PA.1 IP3 (Ref. 1)

Type A and Category I variables are required to meet Regulatory Guide 1.97 Category I (Ref. 2) design and qualification requirements for seismic and environmental qualification, single failure criterion, utilization of emergency standby power, immediately accessible display, continuous readout, and recording of display. Insert B 3.3-124-01

Listed below are discussions of the specified instrument Functions listed in Table 3.3.3-1. These discussions are intended as examples of what should be provided for each Function when the unit specific list is prepared. Insert B 3.3-124-02

(continued)

NUREG-1431 Markup Inserts
ITS SECTION 3.3.3 - POST ACCIDENT MONITORING (PAM) INSTRUMENTATION

INSERT: B 3.3-124-01

Requirements for single failure tolerance and channel diversity are controlled administratively.

INSERT: B 3.3-124-02

The Safety Parameter Display System (SPDS) is provided to the Control Room to continuously displays information from which plant status can be assessed. The SPDS consists of the Critical Functions Monitoring System (CFMS) and the Qualified Safety Parameters Display System (QSPDS). The CFMS displays and alarms critical safety functions (actions which preserve integrity of one or more physical barriers against radiation) in the Control Room and the emergency response facilities. The CFMS is a redundant computer system not designed to seismic and electrical class 1E criteria. The QSPDS is qualified to seismic and electrical class 1E standards (Ref. 4). Note that the Qualified Safety Parameter Display System (QSPDS) is fully qualified to display and record Category 1 instrumentation as recommended by Regulatory Guide 1.97, Rev. 3 (Ref. 1).

DB.1
CLB.1

BASES

LCO (continued)

1/2. ~~Power Range and Source Range~~ Neutron Flux

Covering

~~Power Range and Source Range~~ Neutron Flux indication is provided to verify reactor shutdown. ~~The two ranges are necessary to cover the~~ full range of flux that may occur post accident.

no ¶

Neutron flux is used for accident diagnosis, verification of subcriticality, and diagnosis of positive reactivity insertion.

Insert: B3.3-125-01

2,3 3/4. Reactor Coolant System (RCS) Hot and Cold Leg Temperatures

(wide range)

RCS Hot and Cold Leg Temperatures are Category I variables provided for verification of core cooling and long term surveillance.

required

no ¶

~~RCS hot and cold leg temperatures are used to determine RCS subcooling margin. RCS subcooling margin will allow termination of safety injection (SI), if still in progress, or reinitiation of SI if it has been stopped. RCS subcooling margin is also used for unit stabilization and cooldown control.~~

no ¶

~~In addition,~~ RCS cold leg temperature is used in conjunction with RCS hot leg temperature and steam generator pressure to verify the unit conditions necessary to establish natural circulation in the RCS.

Insert B3.3-125-02

~~Reactor outlet temperature inputs to the Reactor Protection System are provided by two fast response resistance elements and associated transmitters in each loop.~~ The channels provide indication over a range of 32°F to 700°F.

0

Insert: B3.3-125-03

4 5. Reactor Coolant System Pressure (Wide Range)

RCS wide range pressure is a Category I variable provided for verification of core cooling and RCS integrity long term surveillance.

required

~~RCS pressure is used to verify delivery of SI flow to RCS from at least one train when the RCS pressure is~~

(continued)

NUREG-1431 Markup Inserts
ITS SECTION 3.3.3 - POST ACCIDENT MONITORING (PAM) INSTRUMENTATION

INSERT: B 3.3-125-01

To satisfy these requirements, an Excore Neutron Flux Detection System consisting of two detectors (N38, N39) provides two channels of neutron flux indication capable of providing indication from the source range to 100% RTP. Either one of these channels is required to be OPERABLE to satisfy requirements of this LCO. The Excore Neutron Flux Detection System is an indication only system that displays on the QSPDS in the Control Room. Redundancy for this function is provided by the source range, intermediate range and power range instruments of the Nuclear Instrumentation System.

INSERT: B 3.3-125-02

This LCO is satisfied by the OPERABILITY of an one hot leg channel and any one cold leg channel from the following list:

Hot Leg Loop No. 1 (T413A)	Cold Leg Loop No. 1 (T413B)
Hot Leg Loop No. 2 (T423A)	Cold Leg Loop No. 2 (T423B)
Hot Leg Loop No. 3 (T433A)	Cold Leg Loop No. 3 (T433B)
Hot Leg Loop No. 4 (T443A)	Cold Leg Loop No. 4 (T443B)

INSERT: B 3.3-125-03

Redundancy for the Hot Leg RCS Temperature is provided by the core exit thermocouples (Functions 18, 19, 20 and 21) which is considered a diverse variable for the RCS Hot Leg indication. Redundancy for the Cold Leg RCS Temperature is provided by Steam Generator Pressure (Function 15).

BASES

LCO

4 ~~5~~. Reactor Coolant System Pressure (Wide Range) (continued)

~~below the pump shutoff head.~~ RCS pressure is ~~also~~ pressurized used to verify closure of manually closed spray line valves and pressurizer power operated relief valves (PORVs).

mo-71

In addition ~~to these verifications,~~ RCS pressure is used for determining RCS subcooling margin. RCS subcooling margin will allow termination of SI, if still in progress, or reinitiation of SI if it has been stopped. RCS pressure can also be used:

- to determine whether to terminate actuated SI or to reinitiate stopped SI;
- to determine when to reset SI and shut off low head SI;
- to manually restart low head SI;
- as reactor coolant pump (RCP) trip criteria; and
- to make a determination on the nature of the accident in progress and where to go next in the procedure.

RCS subcooling margin is also used for unit stabilization and cooldown control.

RCS pressure is also related to three decisions about depressurization. They are:

- to determine whether to proceed with primary system depressurization;
- to verify termination of depressurization; and
- to determine whether to close accumulator isolation valves during a controlled cooldown/depressurization.

~~A final use of~~ RCS pressure is also used to determine whether to operate the pressurizer heaters.

(continued)

DB.1
CLB.1

BASES

LCO

4 → 5. Reactor Coolant System Pressure (Wide Range) (continued)

depressurization

~~In some units,~~ RCS pressure is a Type A variable because the operator uses this indication to monitor the ~~cooldown~~ of the RCS following a steam generator tube rupture (SGTR) or small break LOCA. Operator actions to maintain a controlled cooldown, such as adjusting steam generator (SG) pressure or level, would use this indication. Furthermore, RCS pressure is one factor that may be used in decisions to terminate RCP operation.

Insert: B3.3-127-01

5 → 6. Reactor Vessel Water Level

required

Reactor Vessel Water Level is ~~provided~~ for verification and long term surveillance of core cooling. It is also used for accident diagnosis and to determine reactor coolant inventory adequacy.

Insert: B3.3-127-02

~~The Reactor Vessel Water Level Monitoring System provides a direct measurement of the collapsed liquid level above the fuel alignment plate.~~ The collapsed level represents the amount of liquid mass that is in the reactor vessel ~~above the core~~. Measurement of the collapsed water level is selected because it is a direct indication of the water inventory.

Insert: B3.3-127-03

6,7 → 7. Containment ~~Sump~~ Water Level (Wide Range) and Recirculation Sump Level

required

Containment ~~Sump~~ Water Level is ~~provided~~ for verification and long term surveillance of RCS integrity.

Containment ~~Sump~~ Water Level is used to determine:

- containment ~~sump~~ level accident diagnosis;
- when to begin the recirculation procedure; and
- ~~whether to terminate SI, if still in progress.~~

Insert: B3.3-127-04

(continued)

NUREG-1431 Markup Inserts
ITS SECTION 3.3.3 - POST ACCIDENT MONITORING (PAM) INSTRUMENTATION

INSERT: B 3.3-127-01

The LCO requirement for 1 channel of RCS Pressure (wide range) indication is satisfied by either the pressure transmitter designated PT-402 or PT-403. Normal control room indication or recorders or displays on the QSPDS in the Control Room will satisfy this requirement.

Redundancy for RCS Pressure (wide range) indication is provided by the RCS 0-3000 psig pressure gauge which is located in an area accessible to plant operators. Additionally, pressure transmitters used to monitor pressurizer pressure (PT-455, PT-456, PT-457 and PT-474) for the range of 1700-2500 psig are available.

INSERT: B 3.3-127-02

This requirement is satisfied by either of the two channels of the Reactor Vessel Level Indicating System (RVLIS). The RVLIS automatically compensate for variations in fluid density as well as for the effects of reactor coolant pump operation.

INSERT: B 3.3-127-03

The level instrumentation is divided into the full range and the dynamic range in order to measure level under all conditions. The full range gives level indication from the bottom of the reactor vessel to the top of the reactor head during natural circulation conditions. The dynamic range gives indication of reactor vessel liquid level for any combination of running RCP's.

INSERT: B 3.3-127-04

The LCO requirement for 1 channel of Containment Recirculation sump water level indication is satisfied by either level the transmitter designated LT-1251 or LT-1252. The LCO requirement for 1 channel of Containment water level (wide range) indication is satisfied by either the level transmitter designated LT-1253 of LT-1254. Normal control room indication will satisfy this requirement.

The refueling water storage tank level (Function 17) provides the diverse variable for measurement for the containment water level. Additionally, 2 channels of containment sump water level indication are available.

BASES

LCO (continued)

8. Containment Pressure (Wide Range)

Insert: B3.3-128-01

Containment Pressure (Wide Range) is ~~provided~~ required for verification of ~~RCS and containment OPERABILITY~~.

~~Containment pressure is used to verify closure of main steam isolation valves (MSIVs), and containment spray Phase B isolation when High-3 containment pressure is reached.~~

Automatic

9. Containment Isolation Valve Position

CIV Position is provided for verification of Containment OPERABILITY, and Phase A and Phase B isolation.

Closed

(or at local control stations for valves without control room indication)

When used to verify Phase A and Phase B isolation, the important information is the isolation status of the containment penetrations. The LCO requires one channel of valve position indication in the control room to be OPERABLE for each ~~active CIV in a~~ containment penetration flow path, ~~i.e., two total channels of CIV position indication for a penetration flow path with two active valves. For containment penetrations with only one active CIV having control room indication, Note (b) requires a single channel of valve position indication to be OPERABLE. This is sufficient to redundantly verify the isolation status of each isolable penetration either via indicated status of the active valve, as applicable, and prior knowledge of a passive valve, or via system boundary status.~~ If a normally active CIV is known to be closed and deactivated, position indication is not needed to determine status. Therefore, the position indication for valves in this state is not required to be OPERABLE. Note (a) to the Required Channels states that the Function is not required for isolation valves whose associated penetration is isolated by at least one closed and deactivated automatic valve, closed manual valve, blind flange, or check valve ~~with flow through the valve secured~~.

DB.1

Insert: B3.3-128-02

(continued)

INSERT: B 3.3-128-01

need for and effectiveness of containment spray and fan cooler units.

The LCO requirement for 1 channel of Containment pressure indication is satisfied by either the pressure transmitter designated PT-1421 or PT-1422. Normal control room indication will satisfy this requirement. Additional containment pressure instrumentation, PT-948A, B & C and PT-949A, B & C, provide a diverse means of establishing containment pressure.

INSERT: B 3.3-128-02

Note that non-automatic containment isolation valves are not provided with position indication. As described in the Bases for LCO 3.6.3, "Containment Isolation Valves, containment isolation valves classified as essential and non-automatic are maintained in the open position and are closed after the initial phases of an accident. Emergency procedures are utilized to control the closing of these valves. Non-essential containment isolation valves are maintained in the closed position and may be opened, if necessary, for plant operation and for only as long as necessary to perform the intended function, under administrative controls described in the Bases for LCO 3.6.3.

DB.1
CLB.1

BASES

LCO (continued)

10. Containment Area Radiation (High Range)

Containment Area Radiation is provided to monitor for the potential of significant radiation releases and to provide release assessment for use by operators in determining the need to invoke site emergency plans. ~~Containment radiation level is used to determine if a high energy line break (HELB) has occurred, and whether the event is inside or outside of containment.~~

Insert: B3.3-129-01

11. Hydrogen Monitors Containment

Hydrogen Monitors are provided to detect high hydrogen concentration conditions that represent a potential for containment breach from a hydrogen explosion. This variable is also important in verifying the adequacy of mitigating actions.

Insert: B3.3-129-02

12. Pressurizer Level

Pressurizer Level 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.

Insert: B3.3-129-03

13, 14 → 13. Steam Generator Water Level (Wide Range) and Narrow Range

SG Water Level is provided Required to monitor operation of decay heat removal via the SGs. ~~The Category I indication of SG level is the extended startup range level instrumentation. The extended startup range level covers a span of ≥ 6 inches to ≤ 394 inches above the lower tubesheet. The measured differential pressure is displayed in inches of water at 68°F.~~

~~Temperature compensation of this indication is performed manually by the operator. Redundant monitoring capability is provided by two trains of instrumentation. The uncompensated level signal is~~

Insert: B3.3-129-04

(continued)

NUREG-1431 Markup Inserts
ITS SECTION 3.3.3 - POST ACCIDENT MONITORING (PAM) INSTRUMENTATION

INSERT: B 3.3-129-01

The LCO requirement for 1 channel of Containment Area Radiation (high range) monitoring is satisfied by either the radiation monitor designated R-25 or R-26.

INSERT: B 3.3-129-02

The LCO requirement for 1 channel of Containment Hydrogen monitoring is satisfied by either the containment hydrogen sampling monitor designated HCMC-A and HCMC-B. Hydrogen monitor OPERABILITY requires that the associated containment fan cooler unit (FCU) is OPERABLE. HCMC-A is associated with FCU 32 or 35 and HCMC-B is associated with FCU 31 or 33 or 34.

INSERT: B 3.3-129-03

The LCO requirement for 2 channels of pressurizer level indication is satisfied by any 2 of the level instruments designated LT-459, LT-460 and LT-461.

INSERT: B 3.3-129-04

Each Steam Generator (SG) contains 4 transmitters that indicate SG water level. Three transmitters per SG indicate narrow range level which is a span that begins at the top of the tube bundles up to the moisture separator. The remaining level transmitter, the wide range instrument, covers the span from the bottom tube sheet up to the moisture separator.

Requirements for steam generator water level indication assume that two of the four steam generators are required for heat removal.

Wide range SG water level is a Category I, Type A variable used to determine if the SG's are being maintained as an adequate heat sink for decay heat removal. The LCO requirement for 2 channels of wide range water level is satisfied by any tow of the instruments designated LT-417D, T-L427D, LT-437D, and LT-447D.

Narrow range SG water level is a Category I, Type A variable used to determine if the SG's are being maintained as an adequate heat sink for decay heat removal and to maintain the SG level and prevent overfill. It is also used to determine whether SI should be terminated and may be used to diagnose an SG tube rupture event. The LCO requirement for 2 channels of narrow range SG water level is satisfied by any 2 instruments from any two different SGs such that all SGs have at least one wide range oe one narrow range instrument:

SG 31	SG 32	SG 33	SG 34
L417A	L427A	L437A	L447A
L417B	L427B	L437B	L447B
L417C	L427C	L437C	L447C

DB.1
CLB.1

BASES

LCO

13. Steam Generator Water Level (Wide Range) (continued)

input to the unit computer, a control room indicator, and the Emergency Feedwater Control System.

SG Water Level (Wide Range) is used to:

- identify the faulted SG following a tube rupture;
- verify that the intact SGs are an adequate heat sink for the reactor;
- determine the nature of the accident in progress (e.g., verify an SGTR); and
- verify unit conditions for termination of SI during secondary unit ~~HELBs outside containment.~~

At some units, operator action is based on the control room indication of SG level. The RCS response during a design basis small break LOCA depends on the break size. For a certain range of break sizes, the boiler condenser mode of heat transfer is necessary to remove decay heat. Extended startup range level is a Type A variable because the operator must manually raise and control SG level to establish boiler condenser heat transfer. Operator action is initiated on a loss of subcooled margin. Feedwater flow is increased until the indicated extended startup range level reaches the boiler condenser setpoint.

Insert: B 3.3-130-01

16

14. Condensate Storage Tank (CST) Level

CST Level is provided to ensure water supply for auxiliary feedwater (AFW). The CST provides the ensured safety grade water supply for the AFW System. The CST consists of two identical tanks connected by a common outlet header. Inventory is monitored by a 0 inch to 144 inch level indication for each tank. CST Level is displayed on a control room indicator, strip chart recorder, and unit computer. In addition, a control room annunciator alarms on low level.

At some units, CST Level is considered a Type A variable because the control room meter and indication

(continued)

INSERT: B 3.3-130-01

15. Steam Generator Pressure

Each SG contains 3 transmitters that indicate SG pressure. Requirements for steam generator pressure indication assume that two of the four steam generators are required for heat removal. Requiring 1 channel per steam generator of SG pressure provides indication for all SGs.

SG pressure is a Category I, Type A variable used to determine if a high energy secondary line rupture occurred and which steam generator is faulted. SG pressure is also used as diverse indication of RCS cold leg temperature for natural circulation determination.

The LCO requirement for 1 channel per steam generator of pressure indication is satisfied by any 1 channel from the following for each of the four SGs:

SG 31	SG 32	SG 33	SG 34
P419A	P429A	P439A	P449A
P419B	P429B	P439B	P449B
P419C	P429C	P439C	P449C

BASES

LCO

16 14. Condensate Storage Tank (CST) Level (continued)

is annunciator are considered the primary indication used by the operator.

The DBAs that require AFW are the loss of electric power, steam line break (SLB), and small break LOCA.

Insert: B 3.3-131-01

Insert: B 3.3-131-02

The CST is the initial source of water for the AFW System. However, as the CST is depleted, manual operator action is necessary to replenish the CST or align suction to the AFW pumps from the hotwell to city water

15, 16, 17, 18

18, 19, 20, 21

Core Exit Temperature

Core Exit Temperature is provided required for verification and long term surveillance of core cooling.

mo 91

An evaluation was made of the minimum number of valid core exit thermocouples (CET) necessary for measuring core cooling. The evaluation determined the reduced complement of CETs necessary to detect initial core recovery and trend the ensuing core heatup. The evaluations account for core nonuniformities, including incore effects of the radial decay power distribution, excore effects of condensate runback in the hot legs, and nonuniform inlet temperatures. Based on these evaluations, adequate core cooling is ensured with two valid Core Exit Temperature channels per quadrant with two CETs per required channel. The CET pair are oriented radially to permit evaluation of core radial decay power distribution. Core Exit Temperature is used to determine whether to terminate SI, if still in progress, or to reinitiate SI if it has been stopped. Core Exit Temperature is also used for unit stabilization and cooldown control.

Insert: B3.3-131-03

Two OPERABLE channels of Core Exit Temperature are required in each quadrant to provide indication of radial distribution of the coolant temperature rise across representative regions of the core. Power distribution symmetry was considered in determining the specific number and locations provided for diagnosis of local core problems. Therefore, two randomly selected thermocouples are not sufficient to

(continued)

NUREG-1431 Markup Inserts
ITS SECTION 3.3.3 - POST ACCIDENT MONITORING (PAM) INSTRUMENTATION

INSERT: B 3.3-131-01

The LCO requirement for 1 channel of CST level indication is satisfied by either the level transmitter designated LT-1128 or LT-1128A. Normal control room indication or displays on the QSPDS in the Control Room will satisfy this requirement. Diverse indication of CST level can be derived from auxiliary feedwater suction pressure indication.

INSERT: B 3.3-131-02

17. Refueling Water Storage Tank (RWST) Level Alarm

Following a LOCA, switchover from the injection phase to the recirculation phase must occur before the RWST empties to prevent damage to the pumps and a loss of cooling capability. For similar reasons, switchover must not occur before there is sufficient water in the containment to support recirculation pump suction. Furthermore, early switchover must not occur to ensure that sufficient borated water is injected from the RWST. The IP3 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 with the RWST level alarm (in conjunction with containment level) as the primary indicator for determining the time for the switchover. Therefore, RWST level alarms are Type A, Category 1 variable. Note that RWST level indication is a Category 2 instrument as recommended in Regulatory Guide 1.97.

The RWST low low level alarm setpoint has both upper and lower limits. The lower limit is selected to ensure switchover occurs before the RWST empties, to prevent ECCS pump damage. The high limit also ensures adequate water inventory in the containment to provide ECCS pump suction.

Requiring 2 channels of RWST level alarm ensures that the alarm function will be available assuming a single failure of one channel. Diverse indication of RWST level can be derived the post LOCA containment water level.

INSERT: B 3.3-131-03

Core exit thermocouples also provide diverse indication for the RCS Hot Leg Temperature.

Four individual channels qualified to satisfy LCO requirements are provided in each quadrant of core. The LCO requirements for core exit thermocouple temperature indication are satisfied by any two channels in each of the 4 core quadrants (i.e., 2 channels per quadrant). Thermocouple readings are obtainable via the plant computer and at a manually selected display unit in the control room.

Requiring 2 channels per core quadrant provides sufficient channels in each of the 4 quadrants to determine the core radial temperature gradient.

BASES

LCO ~~15, 16, 17, 18~~ 18, 19, 20, 21. Core Exit Temperature (continued)

meet the two thermocouples per channel requirement in any quadrant. The two thermocouples in each channel must meet the additional requirement that one is located near the center of the core and the other near the core perimeter, such that the pair of Core Exit Temperatures indicate the radial temperature gradient across their core quadrant. Unit specific evaluations in response to Item II.F.2 of NUREG-0737 (Ref. 3) should have identified the thermocouple pairings that satisfy these requirements. Two sets of two thermocouples ensure a single failure will not disable the ability to determine the radial temperature gradient.

Insert: B 3.3-132-01

19. Auxiliary Feedwater Flow

AFW Flow is provided to monitor operation of decay heat removal via the SGs.

The AFW Flow to each SG is determined from a differential pressure measurement calibrated for a range of 0 gpm to 1200 gpm. Redundant monitoring capability is provided by two independent trains of instrumentation for each SG. Each differential pressure transmitter provides an input to a control room indicator and the unit computer. Since the primary indication used by the operator during an accident is the control room indicator, the PAM specification deals specifically with this portion of the instrument channel.

AFW flow is used three ways:

- to verify delivery of AFW flow to the SGs;
- 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.

(continued)

INSERT: B 3.3-132-01

22. Main Steam Line (MSL) Radiation

The MSL radiation monitors are a Type A variable provided to allow detection of a gross secondary side radioactivity release and to provide a means to identify the faulted steam generator. The LCO requirements for MSL radiation indication are satisfied by one channel in each of the 4 MSLs using instruments designated R62A, R62B, R62C, R62D. Steam generator narrow range level serves as diverse indication for the one monitor per loop provided.

23. Gross Failed Fuel Detector

The gross failed fuel detector (instrument loops R63A, R63B) is a Type A variable provided to allow determination of reactor coolant system radioactivity concentration. The LCO requires i OPERABLE channel and can be satisfied by either R-63A or R-63B.

24. RCS Subcooling

RCS subcooling margin is a Type A variable provided to determine whether to terminate actuated SI or to reinitiate stopped SI, to determine when to terminate reactor coolant pump operation, and for unit stabilization and cooldown control. RCS subcooling margin is calculated and displayed in the plant Safety Parameter Display System. Diverse indication is available using saturation pressure and steam tables.

BASES

LCO

19. Auxiliary Feedwater Flow (continued)

~~At some units, AFW flow is a Type A variable because operator action is required to throttle flow during an SLB accident to prevent the AFW pumps from operating in runout conditions. AFW flow is also used by the operator to verify that the AFW System is delivering the correct flow to each SG. However, the primary indication used by the operator to ensure an adequate inventory is SG level.~~

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

Note 1 has been added in the ACTIONS to exclude the MODE change restriction of LCO 3.0.4. This exception allows entry into the applicable MODE while relying on the ACTIONS even though the ACTIONS may eventually require unit shutdown. This exception is acceptable due to the passive function of the instruments, the operator's ability to respond to an accident using alternate instruments and methods, and the low probability of an event requiring these instruments.

Note 2 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.

(continued)

BASES

ACTIONS (continued)

A.1

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 5.6.8, 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.

A C.1

Condition C applies when one or more Functions have two inoperable required channel~~s~~ ~~(i.e., two channels inoperable in the same Function)~~. Required Action C.1 requires restoring one channel in the Function(s) to OPERABLE status within 7 days. 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

(continued)

BASES

ACTIONS

A C.1 (continued)

of one inoperable channel of the Function limits the risk that the PAM Function will be in a degraded condition should an accident occur. ~~Condition C is modified by a Note that excludes hydrogen monitor channels.~~ CLB.1

Insert B 3.3-135-01

~~D.1~~

~~Condition D applies when two hydrogen monitor channels are inoperable. Required Action D.1 requires restoring one hydrogen monitor channel to OPERABLE status within 72 hours. The 72 hour Completion Time is reasonable based on the backup capability of the Post Accident Sampling System to monitor the hydrogen concentration for evaluation of core damage and to provide information for operator decisions. Also, it is unlikely that a LOCA (which would cause core damage) would occur during this time.~~ CLB.1

B E.1

Condition B applies when the Required Action and associated Completion Time of Condition C or D are not met. Required Action B E.1 requires entering the appropriate Condition referenced in Table 3.3.3-1 for the channel immediately. The applicable Condition referenced in the Table is Function dependent. Each time an inoperable channel has not met any Required Action of Condition C or D, and the associated Completion Time has expired, Condition B is entered for that channel and provides for transfer to the appropriate subsequent Condition.

C F.1 and F.2

A is If the Required Action and associated Completion Time of Conditions C or D 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

(continued)

INSERT: B 3.3-135-01

Condition A also applies when one channel of RWST low level alarm (Table 3.3.31-1, Function 17) is inoperable. Required Action A.1 requires restoring the inoperable channel to OPERABLE status within 7 days. The 7 day Completion Time for restoration redundancy of the alarm function is needed because the IP3 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 with the RWST level alarm (in conjunction with containment sump level) as the primary indicator for determining the time for the switchover.

BASES

ACTIONS

F.1 and F.2 (continued)

from full power conditions in an orderly manner and without challenging unit systems.

Insert: B 3.3-136-01

G.1

At this unit, alternate means of monitoring Reactor Vessel Water Level and Containment Area Radiation have been developed and tested. These alternate means may be temporarily installed if the normal PAM channel cannot be restored to OPERABLE status within the allotted time. If these alternate means are used, the Required Action is not to shut down the unit but rather to follow the directions of Specification 5.6.8, 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.

are available

used

can be

available

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.

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

(continued)

INSERT: B 3.3-136-01

neutron flux, condensate storage tank level, main steam line radiation, gross failed fuel, some containment isolation valves and

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.3.1 (continued)

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.

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

A CHANNEL CALIBRATION is performed every ~~18~~ 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 measured parameter with the necessary range and accuracy. This SR is modified by a Note that excludes neutron detectors. The calibration method for neutron detectors is ~~specified~~ described in the Bases of LCO 3.3.1, "Reactor Trip System (RTS) Instrumentation." The Frequency is based on operating experience and consistency with the typical industry refueling cycle.

REFERENCES

Insert: B3.3-137-01

1. ~~[Unit specific document (e.g., FSAR, NRC Regulatory Guide 1.97 SER letter).]~~
2. Regulatory Guide 1.97, ~~(date)~~. Revision 3
3. NUREG-0737, Supplement 1, "TMI Action Items."
4. FSAR, Section 7.

NUREG-1431 Markup Inserts
ITS SECTION 3.3.3 - POST ACCIDENT MONITORING (PAM) INSTRUMENTATION

INSERT: B 3.3-137-01

Safety Evaluation: Conformance to Regulatory Guide 1.97, Revision 3, for Indian Point 3 (TAC No. 51099), dated April 3, 1991.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.3:
"Post Accident Monitoring (PAM) Instrumentation"

PART 6:

Justification of Differences between

NUREG-1431 and IP3 ITS

JUSTIFICATION OF DIFFERENCES FROM NUREG-1431
ITS SECTION ITS SECTION 3.3.3 - POST ACCIDENT MONITORING (PAM) INSTRUMENTATION

RETENTION OF EXISTING REQUIREMENT (CURRENT LICENSING BASIS)

CLB.1 Table 3.3.3-1 includes those instruments that are Type A or Category I, non-type A instruments taken credit for in the Indian Point 3 Regulatory Guide 1.97 analyses approved by NRC letter dated April 3, 1991, "Emergency Response Capability - Conformance to Regulatory Guide 1.97, Revision 3, for Indian Point 3 (TAC No. 51099)." This LCO requires OPERABILITY of only one channel of each Type A and Category I variable. The additional channels of each Type A and Category I instrument described in Reference 1 and needed to meet Reference 2 requirements for single failure tolerance and channel diversity are controlled administratively.

PLANT-SPECIFIC WORDING PREFERENCE OR MINOR EDITORIAL IMPROVEMENT

PA.1 Corrected typographical error or made a minor editorial improvement to improve clarity and ensure requirements are fully understood and consistently applied. There are no technical changes to requirements as specified in NUREG 1431, Rev. 1; therefore, this change is not a significant or generic deviation from NUREG 1431, Rev 1.

PLANT-SPECIFIC DIFFERENCE IN THE DESIGN OR DESIGN BASIS

DB.1 Design or implementation details are incorporated or revised as necessary to more precisely describe IP3 current design or practice. These changes are intended to describe the design, improve clarity, or ensure requirements are fully understood and consistently applied. Unless identified and described blow, these changes are self-explanatory. A detailed description of the design, accident analysis assumptions, and Operability requirements are incorporated into the IP3 ITS Bases. These changes maintain the IP3 current licensing basis except as identified and justified in the CTS/ITS discussion of changes.

DIFFERENCE BASED ON A GENERIC CHANGE TRAVELER FOR NUREG-1431

None

DIFFERENCE FOR ANY REASON OTHER THAN ABOVE

None

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.4:
"Remote Shutdown Capability"

PART 1:

Indian Point 3
Improved Technical Specifications and Bases

3.3 INSTRUMENTATION

3.3.4 Remote Shutdown

LCO 3.3.4 The Remote Shutdown Functions shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

----------NOTES----------
1. LCO 3.0.4 is not applicable.

2. Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more required Functions inoperable.	A.1	Restore required Function to OPERABLE status.	30 days
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 3.	6 hours
	AND		
	B.2	Be in MODE 4.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.4.1	Perform CHANNEL CHECK for each required instrumentation channel that is normally energized.	31 days
SR 3.3.4.2	Verify each required control circuit and transfer switch is capable of performing the intended function.	24 months
SR 3.3.4.3	----------NOTE---------- Neutron detectors are excluded from CHANNEL CALIBRATION. ---------- Perform CHANNEL CALIBRATION for each required instrumentation channel.	 24 months

B 3.3 INSTRUMENTATION

B 3.3.4 Remote Shutdown

BASES

BACKGROUND

Remote Shutdown provides the control room operator with sufficient instrumentation and controls to place and maintain the unit in a safe shutdown condition from a location other than the control room. This capability is necessary to protect against the possibility that the control room becomes inaccessible. A safe shutdown condition is defined as MODE 3. With the unit in MODE 3, the Auxiliary Feedwater (AFW) System and the main steam safety valves (MSSVs) or the SG atmospheric dump valves (ADVs) can be used to remove core decay heat and meet all safety requirements. The long term supply of water for the AFW System and the ability to borate the Reactor Coolant System (RCS) from outside the control room allows extended operation in MODE 3.

If the control room becomes inaccessible, the operators can establish control at various local control stations and place and maintain the unit in MODE 3. Controls and transfer switches are operated locally at the switchgear, motor control panels, or other local stations. The unit automatically reaches MODE 3 following a unit shutdown and can be maintained safely in MODE 3 for an extended period of time.

The OPERABILITY of the local control and instrumentation functions ensures there is sufficient information available on selected unit parameters to place and maintain the unit in MODE 3 should the control room become inaccessible.

APPLICABLE SAFETY ANALYSES

Remote Shutdown is required to provide equipment at appropriate locations outside the control room to promptly shut down and maintain the unit in a safe condition in MODE 3.

The criteria governing the design and specific system requirements of the Remote Shutdown are located in 10 CFR 50, Appendix A, GDC 19 (Ref. 1).

BASES

APPLICABLE SAFETY ANALYSES (continued)

Remote Shutdown capability and requirements for remote shutdown are presented in Reference 2.

Remote Shutdown is considered an important contributor to the reduction of unit risk to accidents and as such meets Criterion 4 of CFR 50.36.

LCO

The Remote Shutdown LCO provides the OPERABILITY requirements of the instrumentation and controls necessary to place and maintain the unit in MODE 3 from a location other than the control room. The instrumentation and controls required are listed in Bases Table B 3.3.4-1.

The controls, instrumentation, and transfer switches are required for:

- Core reactivity control (initial and long term);
- RCS pressure control;
- Decay heat removal via the AFW System and the MSSVs or SG ADVs;
- RCS inventory control via charging flow; and
- Safety support systems for the above Functions, including service water, component cooling water, and onsite power, including the diesel generators.

A Function of a Remote Shutdown is OPERABLE if all instrument and control channels needed to support the Remote Shutdown Function are OPERABLE. In some cases, Table 3.3.4-1 may indicate that the required information or control capability is available from several alternate sources. In these cases, the Function is OPERABLE as long as one channel of any of the alternate information or control sources is OPERABLE.

BASES

LCO (continued)

The remote shutdown instrument and control circuits covered by this LCO do not need to be energized to be considered OPERABLE. This LCO is intended to ensure the instruments and control circuits will be OPERABLE if unit conditions require that the plant is shutdown from a location other than the control room.

APPLICABILITY

The Remote Shutdown LCO is applicable in MODES 1, 2, and 3. This is required so that the unit can be placed and maintained in MODE 3 for an extended period of time from a location other than the control room.

This LCO is not applicable in MODE 4, 5, or 6. In these MODES, the facility is already subcritical and in a condition of reduced RCS energy. Under these conditions, considerable time is available to restore necessary instrument control functions if control room instruments or controls become unavailable.

ACTIONS

Note 1 is included which excludes the MODE change restriction of LCO 3.0.4. This exception allows entry into an applicable MODE while relying on the ACTIONS even though the ACTIONS may eventually require a unit shutdown. This exception is acceptable due to the low probability of an event requiring remote shutdown and because the equipment can generally be repaired during operation without significant risk of spurious trip.

Note 2 has been added to the ACTIONS to clarify the application of Completion Time rules. Separate Condition entry is allowed for each Function listed on Table 3.3.4-1. 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.

A.1

Condition A addresses the situation where one or more required Remote Shutdown Functions are inoperable. This includes any

BASES

ACTIONS

A.1 (continued)

Function listed in Table 3.3.4-1, as well as the control and transfer switches.

The Required Action is to restore the required Function to OPERABLE status within 30 days. The Completion Time is based on operating experience and the low probability of an event that would require evacuation of the control room.

B.1 and B.2

If the Required Action and associated Completion Time of Condition A is not met, 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 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.

The following Surveillance Requirements are applied to each of the remote shutdown function in Bawes Table B 3.3.4-1, as appropriate.

SURVEILLANCE REQUIREMENTS

The following Surveillance Requirements are applied to each of the remote shutdown functions in Table B 3.3.4-1, as appropriate.

SR 3.3.4.1

Performance of the CHANNEL CHECK once every 31 days 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

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.4.1 (continued)

indication of excessive instrument drift in one of the channels or of something even more serious. 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 the channels are within the criteria, it is an indication that the channels are OPERABLE. 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.

As specified in the Surveillance, a CHANNEL CHECK is only required for those channels which are normally energized.

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

SR 3.3.4.2

SR 3.3.4.2 verifies each required Remote Shutdown control circuit and transfer switch performs the intended function. This verification is performed locally. Operation of the equipment is not necessary. The Surveillance can be satisfied by performance of a continuity check. This will ensure that if the control room becomes inaccessible, the unit can be placed and maintained in MODE 3 from the local control stations. 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. (However, this Surveillance is not required to be performed only during a unit outage.) Operating experience demonstrates that remote shutdown control channels

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.4.2 (continued)

usually pass the Surveillance test when performed at the 24 month Frequency.

SR 3.3.4.3

CHANNEL CALIBRATION is a complete check of the instrument loop and 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 upon operating experience and consistency with the typical industry refueling cycle.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 19.

2. FSAR, Section 7.7.3.

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

FUNCTION/INSTRUMENT OR CONTROL PARAMETER	REQUIRED NUMBER OF FUNCTIONS
1. Reactivity Control	
a. Source Range Neutron Flux	1
b. Reactor Trip Breaker Position	1 per trip breaker
c. Manual Reactor Trip	2
2. Reactor Coolant System (RCS) Pressure Control	
a. Pressurizer Pressure or RCS Wide Range Pressure	1
b. Pressurizer Heaters	1
3. Decay Heat Removal via Steam Generators (SGs)	
a. RCS Hot Leg Temperature (loop 31)	1
b. RCS Cold Leg Temperature (loop 31)	1
c. AFW Controls	1
d. SG Pressure	1
e. SG Level	1
4. RCS Inventory Control	
a. Pressurizer Level	1
b. Charging Pump Controls	1

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.4:
"Remote Shutdown Capability"

PART 2:

CURRENT TECHNICAL SPECIFICATION PAGES

Annotated to show differences between CTS and ITS

CTS pages and associated TSCRs annotated for this ITS Specification :

CTS Page No.	Effective Amendment	Annotated Amendment	TSCR No.	TSCR Description	ITS Status of TSCR
None	N/A	N/A	No TSCRs	No TSCRs for this Page	N/A

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.4:
"Remote Shutdown Capability"

PART 3:

DISCUSSION OF CHANGES

Differences between CTS and ITS

DISCUSSION OF CHANGES
ITS SECTION 3.3.4 - REMOTE SHUTDOWN

ADMINISTRATIVE

None

MORE RESTRICTIVE

M.1 ITS LCO 3.3.4 is added to provide remote shutdown Limiting Conditions for Operation (LCO) for the instrumentation and controls necessary to place and maintain the unit in Mode 3 for an extended period of time from a location other than the control room. This capability is necessary to protect against the possibility that the control room becomes inaccessible. The remote shutdown instrumentation and controls required to be operable are identified in ITS Bases Table 3.3.4-1. There are no equivalent requirements in the CTS, however, FSAR Sections 1.3, 7.7 and 9.6 discuss the capability to shutdown and maintain the plant in a safe condition by means of controls located outside the control room. The remote shutdown LCO is applicable in Modes 1, 2, and 3. In Modes 4, 5, and 6 the unit is already subcritical and in a condition of reduced reactor coolant system energy. Considerable time is available to restore necessary instrument control functions if control room instruments or controls become unavailable. The addition of these requirements is acceptable because it does not introduce any operation which is unanalyzed while requiring more conservative requirements for remote shutdown capability than is currently required. Therefore, this change has no adverse impact on safety.

M.2 ITS LCO 3.3.4 Required Actions A.1, and B.1 and B.2, are added to provide actions to be taken if one or more of the remote shutdown functions are inoperable. If one or more remote shutdown functions is/are inoperable the Required Action is to restore the function to operable status within 30 days. If that Required Action and Completion Time is not met, the unit must be brought to Mode 3 within 6 hours and to Mode 4 within 12 hours. The allowed Completion Time to restore the function to operable status is reasonable based on operating experience and the low probability of an event that would require evacuation of the control room. The shutdown Completion Times are reasonable based on operating experience, to reach the required unit conditions from full

power in an orderly manner and without challenging unit systems. The Actions are modified by two notes. Note 1 excludes the Mode change restriction of LCO 3.0.4. This exception allows entry into an applicable Mode while relying on the Actions even though the Actions may eventually require a unit shutdown. This exception is acceptable due to the low probability of an event requiring remote shutdown of the unit, and because the equipment can generally be repaired during operation without significant risk of a spurious trip. Note 2 clarifies the application of Completion Time rules. Separate Condition entry is allowed for each remote shutdown instrumentation and control function. 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. The addition of these Actions and modifying notes are acceptable because they do not introduce any operation which is unanalyzed while requiring more conservative requirements for remote shutdown capability than is currently required. Therefore, this change has no adverse impact on safety.

M.3 ITS SR 3.3.4.1 is added to require that a Channel Check be performed every 31 days of those channels which are normally energized. The addition of this requirement is acceptable because it ensures that a gross failure of instrumentation has not occurred. It does not introduce any operation which is unanalyzed while requiring more conservative requirements for remote shutdown capability than is currently required. Therefore, this change has no adverse impact on safety.

M.4 ITS SR 3.3.4.2 is added to provide a requirement to verify every 24 months that each required remote shutdown control circuit and transfer switch performs the intended function. The addition of this requirement is acceptable because it ensures that, if the control room becomes inaccessible, the unit can be placed and maintained in Mode 3 from the local control stations. It does not introduce any operation which is unanalyzed while requiring more conservative requirements for remote shutdown capability than is currently required. Therefore, this change has no adverse impact on safety.

M.5 ITS SR 3.3.4.3 is added to require that a Channel Calibration be performed every 24 months on each remote shutdown instrumentation channel (with the exception of the neutron detectors). The addition of this requirement is acceptable because it is a complete check of the instrument loop and sensor, and verifies that the channel responds to a measured parameter within the necessary range and accuracy. It does not introduce any operation which is unanalyzed while requiring more conservative requirements for remote shutdown capability than is currently required. Therefore, this change has no adverse impact on safety.

LESS RESTRICTIVE

None

REMOVED DETAIL

None

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.4:
"Remote Shutdown Capability"

PART 4:

No Significant Hazards Considerations
for
Changes between CTS and ITS
that are
Less Restrictive

No Significant Hazard Considerations for Changes that are Administrative, More Restrictive, and Removed Details are the same for all Packages. A Copy is included at the end of the Package.

NO SIGNIFICANT HAZARDS EVALUATION
ITS SECTION 3.3.4 - REMOTE SHUTDOWN

LESS RESTRICTIVE
("L.1" Labeled Comments/Discussions)

There are no less restrictive changes for the adoption of this ITS.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.4:
"Remote Shutdown Capability"

PART 5:

NUREG-1431
Annotated to show differences between
NUREG-1431 and ITS

Status of NUREG 1431 Generic Changes for ITS 3.3.4

This ITS Specification is based on NUREG-1431 Specification No. 3.3.4
as modified by the following Generic Changes:

OG No.	TSTF No.	Generic Change Description	NRC STATUS	IP3 STATUS	JD No.
CEOG-060		RELOCATION OF REMOTE SHUTDOWN SYSTEM	Rejected by TSTF	Not Incorporated	N/A
WOG-088		ELIMINATE THE REMOTE SHUTDOWN SYSTEM TABLE OF INSTRUMENTATION AND CONTROLS	TSTF Review	Not Incorporated	N/A

3.3 INSTRUMENTATION

(CTS) 3.3.4 Remote Shutdown System

(DOC M.1) LCO 3.3.4 The Remote Shutdown System Functions in Table 3.3.4-1 shall be OPERABLE. (CLB.1)

(DOC M.1) APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

----------NOTES----------

(DOC M.2) 1. LCO 3.0.4 is not applicable.

2. Separate Condition entry is allowed for each Function.

	CONDITION	REQUIRED ACTION	COMPLETION TIME
(DOC M.2)	A. One or more required Functions inoperable.	A.1 Restore required Function to OPERABLE status.	30 days
(DOC M.2)	B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	6 hours
		AND	
		B.2 Be in MODE 4.	12 hours

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE		FREQUENCY
(DOC M.3)	SR 3.3.4.1	Perform CHANNEL CHECK for each required instrumentation channel that is normally energized.	31 days
(DOC M.4)	SR 3.3.4.2	Verify each required control circuit and transfer switch is capable of performing the intended function.	[18] 24 months
(DOC M.5)	SR 3.3.4.3	----------NOTE---------- Neutron detectors are excluded from CHANNEL CALIBRATION. ---------- Perform CHANNEL CALIBRATION for each required instrumentation channel.	[18] 24 months
	~~SR 3.3.4.4~~	~~Perform TADOT of the reactor trip breaker open/closed indication.~~	~~18 months~~

Table 3.3.4-1 moved to Bases

B

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

NOTE
Reviewer's Note: This table is for illustration purposes only. It does not attempt to encompass every Function used at every unit, but does contain the types of Functions commonly found.

FUNCTION/INSTRUMENT OR CONTROL PARAMETER	REQUIRED NUMBER OF FUNCTIONS
1. Reactivity Control	
a. Source Range Neutron Flux	~~[1]~~
b. Reactor Trip Breaker Position	~~[1 per trip breaker]~~
c. Manual Reactor Trip	~~[2]~~
2. Reactor Coolant System (RCS) Pressure Control	
a. Pressurizer Pressure or RCS Wide Range Pressure	~~[1]~~
b. Pressurizer Power Operated Relief Valve (PORV) Control and Block Valve Control	[1, controls must be for PORV & block valves on same line]
3. Decay Heat Removal via Steam Generators (SGs)	
a. RCS Hot Leg Temperature (loop 31)	~~[1 per loop]~~
b. RCS Cold Leg Temperature (loop 31)	~~[1 per loop]~~
c. AFW Controls ~~Condensate Storage Tank Level~~	~~[1]~~
d. SG Pressure	~~[1 per SG]~~
e. SG Level or AFW Flow	~~[1 per SG]~~
4. RCS Inventory Control	
a. Pressurizer Level	~~[1]~~
b. Charging Pump Controls	~~[1]~~

Pressurizer Heaters

B 3.3 INSTRUMENTATION

B 3.3.4 Remote Shutdown System

BASES

BACKGROUND

The Remote Shutdown System provides the control room operator with sufficient instrumentation and controls to place and maintain the unit in a safe shutdown condition from a location other than the control room. This capability is necessary to protect against the possibility that the control room becomes inaccessible. A safe shutdown condition is defined as MODE 3. With the unit in MODE 3, the Auxiliary Feedwater (AFW) System and the steam generator (SG) safety valves or the SG atmospheric dump valves (ADVs) can be used to remove core decay heat and meet all safety requirements. The long term supply of water for the AFW System and the ability to borate the Reactor Coolant System (RCS) from outside the control room allows extended operation in MODE 3.

main steam

(MSSVs)

If the control room becomes inaccessible, the operators can establish control at the remote shutdown panel and place and maintain the unit in MODE 3. Not all controls and necessary transfer switches are located at the remote shutdown panel. Some controls and transfer switches will have to be operated locally at the switchgear, motor control panels, or other local stations. The unit automatically reaches MODE 3 following a unit shutdown and can be maintained safely in MODE 3 for an extended period of time.

various local control stations

are

The OPERABILITY of the remote shutdown control and instrumentation functions ensures there is sufficient information available on selected unit parameters to place and maintain the unit in MODE 3 should the control room become inaccessible.

local

APPLICABLE SAFETY ANALYSES

The Remote Shutdown System is required to provide equipment at appropriate locations outside the control room with a capability to promptly shut down and maintain the unit in a safe condition in MODE 3.

Insert: B3.3-138-01

The criteria governing the design and specific system requirements of the Remote Shutdown System are located in 10 CFR 50, Appendix A, GDC 19 (Ref. 1).

(continued)

INSERT: B 3.3-138-01

Remote shutdown capability and requirements for remote shutdown are presented in Reference 2.

Criterion 4 of 10 CFR 50.36

BASES

APPLICABLE SAFETY ANALYSES (continued)

~~The~~ Remote Shutdown ~~System~~ is considered an important contributor to the reduction of unit risk to accidents and as such ~~it~~ has ~~been~~ retained in ~~the~~ Technical Specifications ~~as indicated in the NRC Policy Statement.~~

LCO

The Remote Shutdown ~~System~~ LCO provides the OPERABILITY requirements of the instrumentation and controls necessary to place and maintain the unit in MODE 3 from a location other than the control room. The instrumentation and controls ~~typically~~ required are listed in Table 3.3.4-1 in ~~the accompanying LCO.~~

Bases

~~Reviewer's Note: For channels that fulfill GDC 19 requirements, the number of OPERABLE channels required depends upon the unit licensing basis as described in the NRC unit specific Safety Evaluation Report (SER). Generally, two divisions are required OPERABLE. However, only one channel per a given Function is required if the unit has justified such a design, and NRC's SER accepted the justification.~~

The controls, instrumentation, and transfer switches are required for:

- Core reactivity control (initial and long term);
- RCS pressure control;
- Decay heat removal via the AFW System and the ~~SG safety valves~~ or SG ADVs;

MSSVs

- RCS inventory control via charging flow; and
- Safety support systems for the above Functions, including service water, component cooling water, and onsite power, including the diesel generators.

A Function of a Remote Shutdown ~~System~~ is OPERABLE if all instrument and control channels needed to support the Remote Shutdown ~~System~~ Function are OPERABLE. In some cases, Table 3.3.4-1 may indicate that the required information or control capability is available from several alternate sources. In these cases, the Function is OPERABLE as long

(continued)

BASES

LCO (continued)

as one channel of any of the alternate information or control sources is OPERABLE.

plant is shutdown from a location other than the control room

The remote shutdown instrument and control circuits covered by this LCO do not need to be energized to be considered OPERABLE. This LCO is intended to ensure the instruments and control circuits will be OPERABLE if unit conditions require that the ~~Remote Shutdown System be placed in~~ operation.

APPLICABILITY

The Remote Shutdown ~~System~~ LCO is applicable in MODES 1, 2, and 3. This is required so that the unit can be placed and maintained in MODE 3 for an extended period of time from a location other than the control room.

This LCO is not applicable in MODE 4, 5, or 6. In these MODES, the facility is already subcritical and in a condition of reduced RCS energy. Under these conditions, considerable time is available to restore necessary instrument control functions if control room instruments or controls become unavailable.

ACTIONS

Note 1 is included which excludes the MODE change restriction of LCO 3.0.4. This exception allows entry into an applicable MODE while relying on the ACTIONS even though the ACTIONS may eventually require a unit shutdown. This exception is acceptable due to the low probability of an event requiring ~~the~~ Remote Shutdown ~~System~~ and because the equipment can generally be repaired during operation without significant risk of spurious trip.

Note 2 has been added to the ACTIONS to clarify the application of Completion Time rules. Separate Condition entry is allowed for each Function listed on Table 3.3.4-1. 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.

(continued)

BASES

ACTIONS (continued)

A.1

Condition A addresses the situation where one or more required Functions ~~of the~~ Remote Shutdown ~~System~~ are inoperable. This includes any Function listed in Table 3.3.4-1, as well as the control and transfer switches.

The Required Action is to restore the required Function to OPERABLE status within 30 days. The Completion Time is based on operating experience and the low probability of an event that would require evacuation of the control room.

B.1 and B.2

If the Required Action and associated Completion Time of Condition A is not met, 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 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

The following surveillance requirements are applied to each of the remote shutdown functions in Table B 3.3.4-1, as appropriate

SR 3.3.4.1

Performance of the CHANNEL CHECK once every 31 days 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. 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 the channels are

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.4.1 (continued)

within the criteria, it is an indication that the channels are OPERABLE. 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.

As specified in the Surveillance, a CHANNEL CHECK is only required for those channels which are normally energized.

The Frequency of 31 days is based upon operating experience which 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 3.3.4.2

SR 3.3.4.2 verifies each required Remote Shutdown System control circuit and transfer switch performs the intended function. This verification is performed ~~from the remote shutdown panel and~~ locally ~~as appropriate~~. Operation of the equipment ~~from the remote shutdown panel~~ is not necessary. The Surveillance can be satisfied by performance of a continuity check. This will ensure that if the control room becomes inaccessible, the unit can be placed and maintained in MODE 3 from ~~the remote shutdown panel and~~ the local control stations. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. (However, this Surveillance is not required to be performed only during a unit outage.) Operating experience demonstrates that remote shutdown control channels usually pass the Surveillance test when performed at the 18 month Frequency.

DB.1

24

24

SR 3.3.4.3

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.4.3 (continued)

The Frequency of [18] 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 the performance of a TADOT every 18 months. This test should verify the OPERABILITY of the reactor trip breakers (RTBs) open and closed indication on the remote shutdown panel, by actuating the RTBs. The Frequency is based upon operating experience and consistency with the typical industry refueling outage.~~

REFERENCES

1. 10 CFR 50, Appendix A, GDC 19.
2. FSAR Section 7.7.3.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.4:
"Remote Shutdown Capability"

PART 6:

Justification of Differences between

NUREG-1431 and IP3 ITS

JUSTIFICATION OF DIFFERENCES FROM NUREG-1431
ITS SECTION ITS SECTION 3.3.4 - REMOTE SHUTDOWN SYSTEM

RETENTION OF EXISTING REQUIREMENT (CURRENT LICENSING BASIS)

CLB.1 IP3 does not have a remote shutdown system although FSAR Sections 1.3, 7.7 and 9.6 discuss the capability to shutdown and maintain the plant in a safe condition by means of controls located outside the control room. ITS LCO 3.3.4 is added to provide remote shutdown Limiting Conditions for Operation (LCO) for the instrumentation and controls necessary to place and maintain the unit in Mode 3 consistent with the requirements in the FSAR. IP3 ITS 3.3.4 differs from NUREG-1431, Rev. 1, in that IP3 ITS 3.3.4 identifies minimum required remote shutdown features in the Bases rather than as part of the LCO. This change is needed because IP3, not having a remote shutdown system, needs the ability to maintain requirements consistent with FSAR requirements. This change is acceptable because IP3 ITS 3.3.4 represents new Technical Specification requirements for IP3.

PLANT-SPECIFIC WORDING PREFERENCE OR MINOR EDITORIAL IMPROVEMENT

PA.1 Corrected typographical error or made a minor editorial improvement to improve clarity and ensure requirements are fully understood and consistently applied. There are no technical changes to requirements as specified in NUREG 1431, Rev. 1; therefore, this change is not a significant or generic deviation from NUREG 1431, Rev 1.

PLANT-SPECIFIC DIFFERENCE IN THE DESIGN OR DESIGN BASIS

DB.1 Design or implementation details are incorporated or revised as necessary to more precisely describe IP3 current design or practice. These changes are intended to describe the design, improve clarity, or ensure requirements are fully understood and consistently applied. Unless identified and described blow, these changes are self-explanatory. A detailed description of the design, accident analysis assumptions, and Operability requirements are incorporated into the IP3 ITS Bases. These changes maintain the IP3 current licensing basis except as identified and justified in the CTS/ITS discussion of changes.

JUSTIFICATION OF DIFFERENCES FROM NUREG-1431
ITS SECTION ITS SECTION 3.3.4 - REMOTE SHUTDOWN SYSTEM

DIFFERENCE BASED ON A GENERIC CHANGE TRAVELER FOR NUREG-1431

None

DIFFERENCE FOR ANY REASON OTHER THAN ABOVE

None

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.5:

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

PART 1:

Indian Point 3
Improved Technical Specifications and Bases

3.3 INSTRUMENTATION

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

LCO 3.3.5 One channel per bus of the Undervoltage (480 V bus) Function and two channels per bus of the Degraded Voltage (480 V bus) Function shall be OPERABLE.

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

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required channel of Undervoltage Function inoperable in one or more buses.	A.1 Restore channel to OPERABLE status.	1 hour
B. One channel of Degraded Voltage Function inoperable in one or more buses.	B.1 Place channel in trip.	1 hour

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time not met. OR Two channels of Degraded Voltage Function inoperable in one or more buses.	C.1 Enter applicable Condition(s) and Required Action(s) for the associated DG made inoperable by LOP DG start instrumentation.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.5.1	Perform TADOT.	31 days
SR 3.3.5.2	Perform CHANNEL CALIBRATION with Allowable Value as follows:	
	a. Undervoltage (480 V bus) Relay Allowable Value ≥ 200 V.	24 months
	b. Degraded Voltage (480 V bus) Relay (Non-SI) Allowable Value ≥ 421 V with a time delay ≤ 45 seconds.	18 months
	c. Degraded Voltage (480 V bus) Relay (Coincident SI) Allowable Value ≥ 421 V with a time delay ≤ 10 seconds.	18 monhts

B 3.3 INSTRUMENTATION

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

BASES

BACKGROUND

The DGs provide a source of emergency power when offsite power is either unavailable or is insufficiently stable to allow safe unit operation. Undervoltage protection will generate a DG start if a loss of voltage or degraded voltage condition occurs on a 480 V bus.

Two undervoltage relays are provided on each 480 V bus for detecting a bus undervoltage. Either of the two relays is sufficient to satisfy requirements for the 480 V bus undervoltage Function even though the failure of the one remaining undervoltage relay could result in the failure of one DG to start because there is redundancy in the number of EDGs available. The two undervoltage relays are combined in a one-out-of-two logic per bus to generate an undervoltage signal. The allowable value and trip setpoint for this function is established in accordance with Reference 3. Actuation of these relays will trip the bus supply breaker, initiate load shedding, start the DG, and initiate load sequencing. There is no explicit time delay for this function because the undervoltage protection devices are induction type disc relays. Therefore, the time to actual trip will decrease as a function of voltage decrease below the setpoint.

Two degraded voltage relays are provided on each 480 V bus for detecting degraded bus voltage. The relays are combined in a two-out-of-two logic per bus (to prevent spurious actuation). The allowable value and trip setpoint for this function is established in accordance with Reference 3. Function actuation includes a time delay of ≤ 10 seconds if a coincident SI signal indicates accident conditions exist and a time delay of ≤ 45 seconds if no SI signal is generated (i.e., non-accident condition). These time delays ensure proper coordination with plant electrical transients (e.g. large motor starts, fast transfers, etc.). Actuation of these relays will trip the bus supply breaker, which will in turn actuate the undervoltage relays.

BASES

BACKGROUND (Continued)

The LOP start actuation is described in FSAR, Section 8.2 (Ref. 1).

Trip Setpoints and Allowable Values

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 Allowable and bistable device, including their explicit uncertainties, is provided in Engineering Standards Manual IES-3 and IES-3B, Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3) (Ref. 3).

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.

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 2, in which a loss of offsite power is assumed.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The delay times assumed in the safety analysis for the ESF equipment include the 10 second DG start delay, and the appropriate sequencing delay. 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.

The LOP DG start instrumentation channels satisfy Criterion 3 of 10 CFR 50.36.

LCO

The LCO for LOP DG start instrumentation requires that 1 channel per bus of the undervoltage (480 V bus) Function and two channels per bus of the Degraded Voltage (480 V bus) Function must be OPERABLE in MODES 1, 2, 3 and 4 when the LOP DG start instrumentation supports safety systems associated with the ESFAS. In MODES 5 and 6, 1 channel per bus of the undervoltage (480 V bus) Function and two channels per bus of the Degraded Voltage (480 V bus) Function must be OPERABLE whenever the associated DG is required to be OPERABLE to ensure that the automatic start of the DG is available when needed.

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 the required 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)

Because the required channels are specified on a per bus basis, the Condition may be entered separately for each bus as appropriate.

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 in the LCO. 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.

A.1

Condition A applies to the LOP DG start Function with one required channel of the undervoltage function inoperable. Note that LCO 3.3.5 requires that only one of the two undervoltage (480 V bus) channels must be OPERABLE. Therefore, Condition A applies when there is no OPERABLE undervoltage (480 V bus) channel on one or more 480 volt bus(es).

If one required channel is inoperable or one or more 480 V buses, Required Action A.1 requires that channel to be restored to OPERABLE status within 1 hour.

The specified Completion Time of 1 hour to restore an undervoltage (480 V bus) channels to OPERABLE status is needed because this Condition represents a loss of the undervoltage DG starting Function for the associated DG. The 1 hour delay in declaring the DG inoperable is acceptable because of the low probability of an event occurring during this interval.

B.1

Condition B applies when one of the two required degraded voltage channels is inoperable on one or more 480 V bus. Required Action B.1 requires placing the inoperable channel in trip so that trip capability is restored to the 2 out of 2 logic used to initiate this Function. The 1 hour Completion Time takes into account the low probability of an event requiring an LOP start occurring during this interval.

BASES

ACTIONS (continued)

C.1

Condition C applies to each of the LOP DG start Functions when the Required Action and associated Completion Time for Condition A or B are not met. Condition C also applies when two channels of Degraded Voltage Function inoperable in one or more buses. In this Condition, Function trip capability is lost even if one of the channels is placed in trip as specified in Required Action B.1.

In these circumstances the Conditions specified in LCO 3.8.1, "AC Sources – Operating," or LCO 3.8.2, "AC Sources – Shutdown," for the DG made inoperable by failure of the LOP DG start instrumentation are required to be entered immediately. The actions of those LCOs provide for adequate compensatory actions to assure unit safety.

SURVEILLANCE REQUIREMENTS

SR 3.3.5.1

SR 3.3.5.1 is the performance of a TADOT. This test is performed every 31 days. The test checks trip devices that provide actuation signals directly, bypassing the analog process control equipment. 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.

SR 3.3.5.2

SR 3.3.5.2 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, as applicable.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.5.2 (continued)

A CHANNEL CALIBRATION is performed every 24 months for the undervoltage relay and every 18 months for the degraded voltage relay. 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 is based on operating experience and is justified by the assumption of the calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis (Ref. 3).

REFERENCES

1. FSAR, Section 8.2.

2. FSAR, Chapter 14.2.

3. Engineering Standards Manual IES-3 and IES-3B, Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3).

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

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

PART 2:

CURRENT TECHNICAL SPECIFICATION PAGES

Annotated to show differences between CTS and ITS

CTS pages and associated TSCRs annotated for this ITS Specification :

CTS Page No.	Effective Amendment	Annotated Amendment	TSCR No.	TSCR Description	ITS Status of TSCR
3.5-1	26	26	No TSCRs	No TSCRs for this Page	N/A
T 3.5-1(1)	154	154	No TSCRs	No TSCRs for this Page	N/A
T 3.5-1(2)	106	106	No TSCRs	No TSCRs for this Page	N/A
T 3.5-3(3)	151	151	IPN 96-124	AOT for ESF Initiation Instrumentation (Needs Supplement)	Incorporated
4.1-1	97	97	No TSCRs	No TSCRs for this Page	N/A
4.1-2	97	97	No TSCRs	No TSCRs for this Page	N/A
4.1-3	148	148	No TSCRs	No TSCRs for this Page	N/A
4.1-4	107	107	No TSCRs	No TSCRs for this Page	N/A
4.1-5	107 TSCR 97-156	107 TSCR 97-156	IPN 97-156	SR Freq for Main Turbine Stop and Control Valves	Incorporated
T 4.1-1(4)	169 TSCR 98-043	169 TSCR 98-043	IPN 98-043	Instrument Channel Surveillance Intervals Extended to 24 Months	Incorporated

3.5 INSTRUMENTATION SYSTEMS

Operational Safety Instrumentation

~~**Applicability**~~

~~Applies to plant instrumentation systems.~~ A2

~~**Objectives**~~

~~To provide for automatic initiation of the Engineered Safety Features in the event that principal process variable limits are exceeded, and to delineate the conditions of the plant instrumentation and safety circuits necessary to ensure reactor safety.~~

Specification

LCO 3.3.5 Applicability

3.5.1 When the plant is not in the cold shutdown condition (or whenever DG required to be Operable) M.1, the Engineered Safety Features initiation instrumentation setting limits shall be as stated in Table 3.5-1.

SEE ITS 3.3.1 and ITS 3.3.2

3.5.2 For instrumentation testing or instrumentation channel failure, plant operation shall be permitted to continue in accordance with Tables 3.5-2 through 3.5-4. No more than one channel of a particular protection channel set shall be tested at the same time. By definition, an instrumentation channel failure shall not be regarded as a channel being tested.

LCO 3.3.5 Actions

3.5.3 In the event the number of in-service channels of a particular function is less than the minimum number of Operable Channels (Col. 3), or the Minimum Degree of Redundancy (Col. 4) cannot be achieved, operation shall be limited according to the requirement shown in Column 5 of Tables 3.5-2 through 3.5-4.

Add Actions Note: Separate Condition entry A.3

TABLE 3.5-1 (Sheet 1 of 2)

ENGINEERED SAFETY FEATURES INITIATION INSTRUMENT ALLOWABLE VALUES		
No. FUNCTIONAL UNIT	CHANNEL	ALLOWABLE VALUE
1. High Containment Pressure (Hi Level)	Safety Injection	≤ 4.5 psig
2. High Containment Pressure (Hi-Hi Level)	a. Containment Spray b. Steam Line Isolation	≤ 24 psig
3. Pressurizer Low Pressure	Safety Injection	≥ 1700 psig
4. High Differential Pressure Between Steam Lines	Safety Injection	≤ 150 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	≤ 6 sec. time delay for SI actuation ≤ 49% of full steam flow at zero load ≤ 49% of full steam flow at 20% load ≤ 110% of full steam flow at full load ≥ 540°F T_{avg} ≥ 600 psig steam line pressure
6. Steam Generator Water Level (low-low)	Auxiliary Feedwater	≥ 5% of narrow range instrument span each steam generator
7.*a. 480v Bus Undervoltage Relay		≥ 200v**
b. 480v Bus Degraded Voltage Relay (Non-~~SI~~)		≥ 414v with a ≤45 sec time delay
c. 480v Bus Degraded Voltage Relay (Coincident SI)		≥ 421v with a ≤10 sec time delay (L.1)

SEE CTS MASTER MARKUP

SR 3.3.5.3.a

SR 3.3.5.3.b

SR 3.3.5.3.c

Amendment No. ~~28~~, ~~38~~, ~~54~~, ~~108~~, 154

TABLE 3.5-1 (sheet 2 of 2)

A.5

* To be effective after completion of all required modifications.

** The undervoltage protection devices used for diesel generator starting are induction type disc relays; therefore, the time to actual trip will decrease as a function of voltage decrease below the setpoint.

LA2

LA.1

A.4

TABLE 3.5-3 (Sheet 3 of 3)

INSTRUMENTATION OPERATING CONDITION FOR ENGINEERED SAFETY FEATURES

	No. FUNCTIONAL UNIT	1 NO. OF CHANNELS	2 NO. OF CHANNELS TO TRIP	3 MIN. NUMBER OF OPERABLE CHANNELS	4 MIN. DEGREE OF REDUNDANCY	5 OPERATOR ACTION IF CONDITIONS OF COL. 3 OR 4 CANNOT BE MET (Note 6)
LCO 3.3.5	4. LOSS OF POWER a. 480v Bus Undervoltage Relay	2/bus	1/bus	1/bus (1/bus)	0	See Note 1 Req. Act A.1 Req. Act C.1 (A.6)
LCO 3.3.5	b. 480v Bus Degraded Voltage Relay	2/bus	2/bus	2/bus (See Note 2)	0 (Req Act B.1)	See Note 1 Req Act B.1 Req Act C.1
SEE ITS 3.4.12	5. OVERPRESSURE PROTECTION SYSTEM (OPS)	3	2	2	1	See Note 7

Req Act C.1 ~~Note 1.~~ If the 138KV and 13.8KV sources of offsite power are available and the conditions of column 3 or 4 cannot be met within 72 hours, then the requirements of 3.7.C.1 or 2 shall be met. (Declare DG inoperable) (M.1.)

Req Act B.1 Note 2. If one channel becomes inoperable, it is placed in the trip position and the minimum number of operable channels is reduced by one. (A.6) (A.1)

Note 3. Permissible to bypass if reactor coolant pressure is less than 2000 psig.

Note 4. Must actuate 2 switches simultaneously.

Note 5. The Minimum Number of Operable Channels and the Minimum Degree of Redundancy may be reduced to zero if the SI bypass is in the unblocked position.

SEE CTS MASTER MARKUP

Note 6. If the condition of Column 3 or 4 cannot be met, the reactor shall be placed in the hot shutdown condition, utilizing normal operating procedures, within 4 hours of the occurrence. If the conditions are not met within 24 hours of the occurrence, the reactor shall be placed in the cold shutdown condition, or the alternate condition, if applicable, within an additional 24 hours.

Note 7. Refer to Specification 3.1.A.8.

Note 8. Main steam isolation valves may be closed in lieu of going to cold shutdown if the circuitry associated with closing the valves is the only portion inoperable.

4 SURVEILLANCE REQUIREMENTS

4.1 OPERATIONAL SAFETY REVIEW

Applicability

Applies to items directly related to safety limits and limiting conditions for operation. Performance of any surveillance test outlined in these specifications is not required if the plant condition is the same as the condition into which the plant would be placed by an unsatisfactory result of that test. Failure to perform a surveillance requirement within the allowed surveillance interval (including extensions specified in definition 1.12), shall constitute noncompliance with the operability requirements of the limiting conditions for operation (LCOs). The time limits for associated action requirements are applicable at the time it is identified that a surveillance requirement has not been performed. Action requirements may be delayed for up to 24 hours to permit completion of the missed surveillance when the allowable outage time limits of the action requirements are less than 24 hours (i.e. for LCOs of less than 24 hours, a 24 hour delay period is permitted before entering the LCO; for LCOs greater than 24 hours, no delay period is permitted).

Objective

To specify the minimum frequency and type of surveillance to be applied to plant equipment and conditions.

Specification

A. Calibration, testing, and checking of analog channel and testing of logic channel shall be performed as specified in Table 4.1-1.

B. Sampling and equipment tests shall be conducted as specified in Table 4.1-2 and 4.1-3, respectively.

A.1

Basis

A surveillance test is intended to identify conditions in a plant that would lead to a degradation of reactor safety. Should a test reveal such a condition, then the Technical Specifications require that, either immediately or after a specified period of time, the plant be placed in a condition which mitigates or eliminates the consequences of additional related casualties or accidents. If the plant is already in a

A.1

condition which would satisfy the failure criteria of the test, then plant safety is assured and performance of the test yields either meaningless information or information that is not necessary to determine safety limits or limiting conditions for operation of the plant.

Likewise, systems and components are assumed to be operable as defined in paragraph 1.5, and satisfying safety limits or LCOs for a given plant operating condition, when surveillance requirements have been satisfactorily performed within the allowed surveillance interval and extensions as specified in definition 1.12. However, nothing in this provision shall be construed as implying that systems or components are operable when they are found or known to be inoperable although still meeting the surveillance requirements. LCO action requirements associated with operation in a degraded mode are applicable when surveillance requirements have not been completed within the allowed surveillance interval. The time limits of such LCOs apply from the point in time it is identified that a surveillance has not been performed and not at the time the allowed surveillance interval was exceeded.

For a missed surveillance, if the allowable outage time limits of the applicable LCO action requirements are less than 24 hours or a shutdown is required, then a 24-hour delay is permitted in implementing the action requirements. The purpose of the delay is to permit the completion of a missed surveillance before a shutdown or some other remedial measure precludes completion of the surveillance. This allowance of a delay includes consideration of the plant conditions, adequate planning, availability of personnel, the time required to perform the surveillance, and the safety significance of the delay in completing the required surveillance. If a surveillance is not completed within the 24-hour delay, than the time limits of the associated action requirements are applicable at the time. When a surveillance is performed within the 24-hour delay and the Surveillance Requirements are not met (e.g. the system or component is declared inoperable), the time limits of the LCO action requirements are applicable at that time.

Failure to perform the surveillance within the allowed surveillance interval and extension as specified in definition 1.12 is still a violation of the LCO operability requirement subject to enforcement and reportability requirements as may be applicable.

Definition 1.12 establishes the limit for which the specified time interval for Surveillance Requirements may be extended.

A.1

It permits an allowable extension of the normal surveillance interval to facilitate surveillance scheduling and consideration of plant operating conditions that may not be suitable for conducting the surveillance; e.g. transient conditions or other ongoing surveillance or maintenance activities. It also provides flexibility to accommodate the length of a fuel cycle for surveillances that are performed at each refueling outage and are specified with an 18-month or 24-month surveillance interval. It is not intended that this provision be used repeatedly as a convenience to extend surveillance intervals beyond that specified for surveillances that are not performed on an 18-month or 24-month basis. Likewise, it is not the intent that 24 month surveillances be performed during power operation unless it is consistent with safe plant operation. The limitation of Definition 1.12 is based on engineering judgement and the recognition that the most probable result of any particular surveillance being performed is the verification of conformance with the Surveillance Requirements. This provision is sufficient to ensure that the reliability ensured through surveillance activities is not significantly degraded beyond that obtained from the specified surveillance interval. The phrase "at least" associated with a surveillance frequency does not negate the 25% extension allowance of Definition 1.12; instead, it permits the performance of more frequent surveillance activities.

Based on experience in operation of both conventional and nuclear plant systems, when the plant is in operation, the minimum checking frequency of once per shift is deemed adequate for reactor and steam system instrumentation.

Calibration

Calibrations are performed to ensure the presentation and acquisition of accurate information.

The nuclear flux (linear level) channels are calibrated daily against a heat balance standard to account for errors induced by changing rod patterns and core physics parameters.

Other channels are subject only to the "drift" errors induced within the instrumentation itself and, consequently, can tolerate longer intervals between calibration. Process system instrumentation errors induced by drift can be expected to remain within acceptable tolerances if recalibration is performed at intervals of 18 or 24 months.

Substantial calibration shifts within a channel (essentially a channel failure) will be revealed during routine checking and testing procedures.

Thus, minimum calibration frequencies of once-per-day for the nuclear flux (linear level) channels, and 18 or 24 months for the process system channels is considered acceptable.

A.1

Testing

The minimum testing frequency for those instrument channels connected to the safety system is based on an average unsafe failure rate of 2.5×10^{-6} failure hrs. per channel. This is based on operating experience at conventional and nuclear plants. An unsafe failure is defined as one which negates channel operability and which, due to its nature, is revealed only when the channel is tested or attempts to respond to a bona fide signal.

For a specified test interval W and an M out of N redundant system with identical and independent channels having a constant failure rate λ, the average availability A is given by:

$$A = \frac{W-Q\left(\frac{W}{N-M+2}\right)}{W} = 1 - \frac{N!}{(N-M+2)!\,(M-1)!}(\lambda W)^{N-M+1}$$

where A is defined as the fraction of time during which the system is functional, and Q is the probability of failure of such a system during a time interval W.

For a 2-out-of-3 system A = 0.9999708, assuming a channel failure rate, λ, equal to 2.5×10^{-6} hr $^{-1}$ and a test interval, W, equal to 2160 hrs.

This average availability of the 2-out-of-3 system is high, hence the test interval of one quarter is acceptable.

Because of their greater degree of redundancy, the 1/3 and 2/4 logic arrays provide an even greater measure of protection and are thereby acceptable for the same testing interval. Those items specified for quarterly testing are associated with process components where other means of verification provide additional assurance that the channel is operable, thereby requiring less frequent testing.

~~Specified surveillance intervals for the Reactor Protection System and Engineered Safety Features have been determined in accordance with WCAP - 10271, Supplement 1, "Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System," and WCAP - 10271, Supplement 2, Revision 1, "Evaluation of Surveillance Frequencies and Out of Service Times for the Engineered Safety Features Actuation System," as approved by the NRC and documented in the SERs (letters to J. J. Sheppard from C. O. Thomas, dated February 21, 1985, and to R. A. Newton from C. E. Rossi, dated February 22, 1989). Surveillance intervals were determined based on maintaining an appropriate level of reliability of the Reactor Protection System and Engineered Safety Features instrumentation.~~

DELETED

Amendment No. ~~93~~, ~~107~~, TSCR 97-156

TABLE 4.1-1 (Sheet 4 of 6)

	Channel Description	Check	Calibrate	Test	Remarks
25.	Level Sensors in Turbine Building	N.A.	N.A.	24M	
26.	Volume Control Tank Level	N.A.	24M	N.A.	
27.	Boric Acid Makeup Flow Channel	N.A.	24M	N.A.	
28.	Auxiliary Feedwater:				
	a. Steam Generator Level	S	24M	Q	Low-Low
	b. Undervoltage	N.A.	24M	24M	
	c. Main Feedwater Pump Trip	N.A.	N.A.	24M	
29.	Reactor Coolant System Subcooling Margin Monitor	D	24M	N.A.	
30.	PORV Position Indicator	N.A.	N.A.	24M	Limit Switch
31.	PORV Position Indicator	D	24M	24M	Acoustic Monitor
32.	Safety Valve Position Indicator	D	24M	24M	Acoustic Monitor
33.	Auxiliary Feedwater Flow Rate	N.A.	18M	N.A.	
34.	Plant Effluent Radioiodine/ Particulate Sampling	N.A.	N.A.	18M	Sample line common with monitor R-13
35.	Loss of Power		SR 3.3.5.2	SR 3.3.5.1	
	a. 480v Bus Undervoltage Relay	N.A.	24M	M	
	b. 480v Bus Degraded Voltage Relay	N.A.	18M	M	
	~~c. 480v Safeguards Bus Undervoltage Alarm~~	~~N.A.~~	~~24M~~	~~M~~	LA3
36.	Containment Hydrogen Monitors	D	Q	M	

SR 3.3.5.2

SR 3.3.5.1

Amendment No. 38, 44, 54, 65, 67, 74, 93, 123, 136, 137, 142, 144, 150, 168, 169, TSCR 98-043

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.5:

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

PART 3:

DISCUSSION OF CHANGES

Differences between CTS and ITS

DISCUSSION OF CHANGES
ITS SECTION 3.3.5 - LOSS OF POWER (LOP) DIESEL
GENERATOR (DG) START INSTRUMENTATION

ADMINISTRATIVE

A.1 In the conversion of the Indian Point Unit 3 Current Technical Specifications (CTS) to the plant specific Improved Technical Specifications (ITS) certain wording preferences or conventions are adopted which do not result in technical changes (either actual or interpretational). Additionally, editorial changes, reformatting, and revised numbering are adopted to make ITS consistent with the conventions in NUREG-1431, Standard Technical Specifications, Westinghouse Plants, Rev. 1, i.e., the improved Standard Technical Specifications.

The CTS Bases are deleted and replaced with comprehensive ITS Bases designed to support interpretation and implementation of the associated Technical Specifications. The Bases explain, clarify, and document the reasons (i.e., bases) for the associated Technical Specifications, and reflect the IP3 plant specific design, analyses, and licensing basis. In accordance with 10 CFR 50.36(a), the ITS Bases are included with the proposed ITS conversion application; however, deletion of the CTS Bases and the adoption of the ITS Bases is an administrative change with no impact on safety.

A.2 CTS Limiting Conditions for Operation (LCOs) and Surveillance Requirements (SRs) include statements of the objective and the applicability. The CTS statements of objective and applicability are deleted because these statements do not establish any requirements and do not provide any guidance for the application of CTS requirements. Therefore, deletion of these statements has no significant adverse impact on safety.

A.3 The Actions for ITS 3.3.5, Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation, are preceded by a Note that specifies: "Separate Condition entry is allowed for each Function." This allowance provides explicit recognition that the ITS is designed to allow completely separate re-entry into any Condition for each train and/or channel addressed by the Condition. This includes separate tracking of

Completion Times based on this re-entry. This allowance is consistent with an unstated assumption in the CTS. Therefore, the addition of this Note is an administrative change with no impact on safety.

A.4 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.

Operable channel is defined as a channel that will generate a single protective action signal when required by a plant condition; this definition excludes any channel in the tripped condition. The CTS requirement for minimum operable channels is designed to ensure that sufficient channels are available to adequately monitor the associated plant condition.

Minimum degree of redundancy is defined as the difference between the number of operable channels and the number of channels which when tripped will cause an automatic system trip. The CTS requirement for minimum degree of redundancy is designed to ensure the required ability to trip including a tolerate for random failures of protective and/or control circuits.

CTS allows plant operation to continue indefinitely with an inoperable channel only if the required minimum number of channels (function) is maintained and the required level of redundancy (failure tolerance) is maintained.

ITS LCOs specify a minimum number of Required Channels only and uses LCO Required Actions that specify if a required channel may be placed in trip or must be restored to Operable. The Required Actions are specific to each Function and specify the actions that will ensure that both the minimum number of channels and minimum level of redundancy are maintained when one or more channels are inoperable.

Therefore, except as addressed in the discussion associated with each Function, there is no change to the existing requirements for minimum number of operable channels or minimum degree of redundancy except these

requirements are enforced by the combination of a requirement for a minimum number of channels and a specific requirement to restore or trip an inoperable channel. This is an administrative change with no adverse impact on safety because there is no change to the existing requirements.

A.5 CTS Table 3.5-1, Note *, modifying item 7, states that the requirements are to be effective after completion of all required modifications. ITS LCO 3.3.5 does not retain this note because the modifications are completed. Deletion of the note is an administrative change.

A.6 CTS Table 3.5-3, Notes 1 and 2, provide actions to be taken if one or more undervoltage (480 V bus) relay channels or degraded Voltage (480 V bus) channels are inoperable. No Completion Time is specified, therefore the time is assumed to be zero per CTS 3.0. This is interpreted to require the action be initiated as soon as possible and be completed within 1 hour. ITS 3.3.5, Required Action A.1, requires that an inoperable undervoltage (480 V bus) relay channel be restored to Operable within 1 hour or the EDG must be declared inoperable. ITS 3.3.5, Required Action B.1, requires that an inoperable degraded voltage (480 V bus) relay channel be tripped within 1 hour or the EDG must be declared inoperable. The establishment of an explicit Completion Time of 1 hour for these actions is administrative change with no adverse impact on safety because it is a reasonable interpretation of the equivalent CTS requirement.

MORE RESTRICTIVE

M.1 CTS Applicability requirements for the LOP DG start instrumentation are implied by CTS 3.5.1 which requires that instrument setpoints must meet requirements only when not in the cold shutdown condition and CTS Table 3.5-3, Note 1, which requires that actions for inoperable DG when above cold shutdown are taken if the LOP DG start instrumentation is not Operable. CTS Table 3.5-3, Note 1 does not include required actions for the shutdown or refueling modes, where CTS 3.7.F.3 and 3.7.F.4 require,

as a minimum, two of the four 480 V buses to be energized, and two diesel generators to be operable because autstart of the EDGs is not required in these Modes.

ITS LCO 3.3.5 maintains the requirement that LOP DG start instrumentation is Operable above cold shutdown (i.e., Modes 1, 2, 3 and 4); however, ITS LCO 3.3.5 requires that LOP DG start instrumentation is Operable whenever a DG is required to be Operable (i.e., Modes 5 and 6 (if fuel is being moved) and during movement of irradiated fuel assemblies.

This change is needed because it ensures that the LOP DG start instrumentation is Operable whenever a DG is Operable. This more restrictive change is acceptable because if does not introduce any operation that is un-analyzed while ensuring that DG autostart instrumentation is Operable whenever a DG is required to be Operable. Therefore, this change has no significant adverse impact on safety.

LESS RESTRICTIVE

L.1 CTS trip setpoint limiting safety system setting (allowable value) are based on the IP3 Plant Manual, Volume VI: Precautions, Limitations, and Setpoints, March 1975. ITS will use allowable values calculated in accordance with Engineering Standards Manual IES-3 and IES-3B, Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3). This change is needed because the limiting safety system settings established by IP3 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 Engineering Standards Manual IES-3 and IES-3B, Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3) 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.

REMOVED DETAIL

LA.1 CTS Section 3.5, Tables 3.5-2, 3.5-3 and 3.5-4, Columns 1 and 2, identify the number of channels and the channels required to trip for each RPS and ESFAS Function. ITS LCO 3.3.1, LCO 3.3.2, LCO 3.3.3, LCO 3.3.5 and LCO 3.3.6 require that these Functions be Operable but do not provide system design details. This is acceptable because this design information is incorporated into the minimum requirements and ITS specifies the minimum requirements for Operability.

This change is acceptable because ITS LCO 3.3.1, LCO 3.3.2, LCO 3.3.3, LCO 3.3.5 and LCO 3.3.6 maintain the existing requirements for the Operability of these instruments (except as identified and justified in this discussion of change); therefore, there is no change to the existing requirements and no change to the level of safety of facility operation.

This change, which allows the description of the design of instrument functions to be maintained in the FSAR and the detailed description of the requirements for Operability of these functions to be maintained in the ITS Bases, is consistent with the approach used in NUREG-1431 for all Limiting Conditions for Operation (LCOs). This approach is acceptable because the requirements of 10 CFR 50.59, Changes, Tests and Experiments, and ITS 5.5.13, Technical Specifications (TS) Bases Control Program, are designed to assure that changes to the FSAR and ITS Bases do not result in changes to the Technical Specification requirements and do not result in significant increases in the probability or consequences of accidents previously evaluated, do not create the possibility of a new or different kind of accident, and do not result in a significant reduction in a margin of safety. Additionally, IP3 programs that implement FSAR changes in accordance with 10 CFR 50.59 and

ITS Bases changes in accordance with ITS 5.5.13 require periodic submittal of FSAR and Bases changes to the NRC for review.

This change is a less restrictive administrative change with no impact on safety because no requirements are being deleted from Technical Specifications and an appropriate change control process and an appropriate level of regulatory oversight are maintained for the information being relocated out of the Technical Specifications.

LA.2 CTS Table 3.5-1, Note **, explains why there are no explicit time delay requirements for the 480 V Bus undervoltage relay. This note states that the undervoltage protection devices used for diesel generator starting are induction type disc relays; therefore, the time to actual trip will decrease as a function of voltage decrease below the setpoint. This detail is not included in ITS 3.3.5, and is relocated to the FSAR and LCO 3.3.5 Bases.

This change is acceptable because ITS LCO 3.3.5 maintain the existing requirement for the Operability of the 480 V Bus undervoltage relay (except as identified and justified in this discussion of change); therefore, there is no change to the existing requirements and no change to the level of safety of facility operation.

This change, which allows the description of the design of instrument functions to be maintained in the FSAR and the detailed description of the requirements for Operability of these functions to be maintained in the ITS Bases, is consistent with the approach used in NUREG-1431 for all Limiting Conditions for Operation (LCOs). This approach is acceptable because the requirements of 10 CFR 50.59, Changes, Tests and Experiments, and ITS 5.5.13, Technical Specifications (TS) Bases Control Program, are designed to assure that changes to the FSAR and ITS Bases do not result in changes to the Technical Specification requirements and do not result in significant increases in the probability or consequences of accidents previously evaluated, do not create the possibility of a new or different kind of accident, and do not result in a significant reduction in a margin of safety. Additionally, IP3 programs that implement FSAR changes in accordance with 10 CFR 50.59 and

ITS Bases changes in accordance with ITS 5.5.13 require periodic submittal of FSAR and Bases changes to the NRC for review.

This change is a less restrictive administrative change with no impact on safety because no requirements are being deleted from Technical Specifications and an appropriate change control process and an appropriate level of regulatory oversight are maintained for the information being relocated out of the Technical Specifications.

LA.3 CTS Table 4.1-1 includes requirements for the testing of the 480 V safeguards bus undervoltage alarm. This requirement is not included in ITS 3.3.5 and is relocated to the FSAR and plant procedures.

This change, which allows testing of the 480 V safeguards bus undervoltage alarm to be maintained in the FSAR and implemented by procedures, is acceptable because the requirements of 10 CFR 50.59, Changes, Tests and Experiments, are designed to assure that changes to the FSAR do not result in changes to the Technical Specification requirements and do not result in significant increases in the probability or consequences of accidents previously evaluated, do not create the possibility of a new or different kind of accident, and do not result in a significant reduction in a margin of safety. Additionally, IP3 programs that implement FSAR changes in accordance with 10 CFR 50.59 require periodic submittal of FSAR and Bases changes to the NRC for review.

This change is a less restrictive administrative change with no impact on safety because an appropriate change control process and an appropriate level of regulatory oversight are maintained for the information being relocated out of the Technical Specifications.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.5:

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

PART 4:

No Significant Hazards Considerations for Changes between CTS and ITS that are Less Restrictive

No Significant Hazard Considerations for Changes that are Administrative, More Restrictive, and Removed Details are the same for all Packages. A Copy is included at the end of the Package.

NO SIGNIFICANT HAZARDS EVALUATION
ITS SECTION 3.3.5 - LOSS OF POWER (LOP)
DIESEL GENERATOR (DG) START INSTRUMENTATION

LESS RESTRICTIVE
("L.1" Labeled Comments/Discussions)

New York Power Authority has evaluated the proposed Technical Specification change identified as "Less Restrictive" in accordance with the criteria set forth in 10 CFR 50.92, and has determined that the proposed change does not involve a significant hazards consideration. The bases for the determination that the proposed change does not involve a significant hazards consideration are discussed below.

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

   CTS trip setpoint limiting safety system setting (allowable value) are based on the IP3 Plant Manual, Volume VI: Precautions, Limitations, and Setpoints, March 1975. ITS will use allowable values calculated in accordance with Engineering Standards Manual IES-3 and IES 3-B, Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3). This change is needed because the limiting safety system settings established by IP3 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 will not result in a significant increase in the probability of an accident previously evaluated because a small change in the allowable value for an RPS or ESFAS actuation instrumentation is not assumed as the initiator of any accident previously evaluated. This change will not result in a significant increase in the consequences of an accident previously evaluated because the allowable values calculated in accordance with Engineering Standards Manual IES-3 and IES-3B, Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3). This methodology ensures 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 provides 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.

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

   The proposed change will not involve any physical changes to systems, structures, or components, or involve a change in normal plant operation. Therefore, it will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   This change does not involve a significant reduction in a margin of safety because the existing limiting safety system setting and the proposed allowable values use the information and methods available at the time to determine instrument settings that ensure that safety limits are not exceeded during any event.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.5:

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

PART 5:

NUREG-1431
Annotated to show differences between NUREG-1431 and ITS

Status of NUREG 1431 Generic Changes for ITS 3.3.5

This ITS Specification is based on NUREG-1431 Specification No. **3.3.5**
as modified by the following Generic Changes:

OG No.	TSTF No.	Generic Change Description	NRC STATUS	IP3 STATUS	JD No.
WOG-017	091 R0	RELOCATE THE TRIP SETPOINTS AND ALLOWABLE VALUES FOR LOSS OF VOLTAGE AND UNDERVOLTAGE TO THE BASES	See Next Rev	Not Incorporated	N/A

3.3 INSTRUMENTATION

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

(3.5.2) LCO 3.3.5 ~~Three~~ One channel~~s~~ per bus of the loss of voltage Function and ~~Three~~ Two channels per bus of the degraded voltage Function shall be OPERABLE.

Insert: 3.3-47-01

Insert: 3.3-47-02

(3.5.1) (DOC A.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

(DOC A.3)

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one channel per bus inoperable.	A.1 ---NOTE--- The inoperable channel may be bypassed for up to 4 hours for surveillance testing of other channels. --- Place channel in trip.	6 hours
B. One or more Functions with two or more channels per bus inoperable.	B.1 Restore all but one channel to OPERABLE status.	1 hour

Insert: 3.3-47-03

(continued)

NUREG-1431 Markup Inserts
ITS SECTION 3.3.5 - LOSS OF POWER (LOP) DIESEL GENERATOR (DG) START INSTRUMENTATION

INSERT: 3.3-47-01

Undervoltage (480 V bus)

INSERT: 3.3-47-02

Degraded Voltage (480 V bus)

INSERT: 3.3-47-03

<T 3.5-3, #4.a> <DOC A.6> A.	One required channel of Undervoltage Function inoperable in one or more buses.	A.1 Restore channel to OPERABLE status.	1 hour
<T 3.5-3 4.b> <DOC A.6> B.	One channel of Degraded Voltage Function inoperable in one or more buses.	B.1 Place channel in trip.	1 hour

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
<T3.5-3, Note 1> <DOC M.1> C. Required Action and associated Completion Time not met.	C.1 Enter applicable Condition(s) and Required Action(s) for the associated DG made inoperable by LOP DG start instrumentation.	Immediately

Imant: 3.3-48-01

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
~~SR 3.3.5.1~~	~~Perform CHANNEL CHECK.~~	~~12 hours~~
T 4.1-1, #35a #35b SR 3.3.5.~~2~~ 1	Perform TADOT.	{31 days}

(continued)

NUREG-1431 Markup Inserts
ITS SECTION 3.3.5 - LOSS OF POWER (LOP) DIESEL GENERATOR (DG) START INSTRUMENTATION

INSERT: 3.3-48-01

OR

Two channels of Degraded Voltage Function inoperable in one or more buses.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.5.~~3~~ 2	Perform CHANNEL CALIBRATION with ~~[setpoint Allowable Value]~~ ~~[Trip Setpoint and Allowable Value]~~ as follows:	~~[18] months~~
	a. Loss of voltage Allowable Value ≥ [2912] V with a time delay of [0.8] ± [ ] second. Loss of voltage Trip Setpoint ≥ [2975] V with a time delay of [0.8] ± [ ] second.	
	b. Degraded voltage Allowable Value ≥ [3683] V with a time delay of [20] ± [ ] seconds. Degraded voltage Trip Setpoint ≥ [3746] V with a time delay of [20] ± [ ] seconds.	

Insert: 3.3-49-01

NUREG-1431 Markup Inserts
ITS SECTION 3.3.5 - LOSS OF POWER (LOP) DIESEL GENERATOR (DG) START INSTRUMENTATION

INSERT: 3.3-49-01

<T.4.1-1, #35.a> <T 3.5-1, #7.a> <DOC LA.2>	a.	Undervoltage (480 V bus) Relay Allowable Value ≥ 200 V.	24 months
<T 3.5-1, #7.b> <T 4.1-1, #35.b> <DOC L.1>	b.	Degraded Voltage (480 V bus) Relay (Non-SI) Allowable Value ≥ 421 V with a time delay ≤ 45 seconds.	18 months
<T 3.5-1, #7.c> <T 4.1-1, #35.b> <DOC L.1>	c.	Degraded Voltage (480 V bus) Relay (Coincident SI) Allowable Value ≥ 421 V with a time delay ≤ 10 seconds.	18 monhts

B 3.3 INSTRUMENTATION

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

BASES

BACKGROUND

The DGs provide a source of emergency power when offsite power is either unavailable or is insufficiently stable to allow safe unit operation. Undervoltage protection will generate an LOP start if a loss of voltage or degraded voltage condition occurs in the switchyard. There are two LOP start signals, one for each 4.16 kV vital bus.

a DG

Insert: B 3.3-144-01

Three undervoltage relays with inverse time characteristics are provided on each 4160 Class 1E instrument bus for detecting a sustained degraded voltage condition or a loss of bus voltage. The relays are combined in a two-out-of-three logic to generate an LOP signal if the voltage is below 75% for a short time or below 90% for a long time. The LOP start actuation is described in FSAR, Section 8.3 (Ref. 1).

Trip Setpoints and Allowable Values

Insert B 3.3-144-02

The Trip Setpoints used in the relays are based on the analytical limits presented in FSAR, Chapter 15 (Ref. 2). The selection of these Trip Setpoints is such that adequate protection is provided when all sensor and processing time delays are taken into account.

The actual nominal Trip Setpoint entered into the relays is normally still more conservative than that required by the Allowable Value. If the measured setpoint does not exceed the Allowable Value, the relay is considered OPERABLE.

Setpoints adjusted in accordance with the Allowable Value ensure that the consequences of accidents will be acceptable, providing the unit is operated from within the LCOs at the onset of the accident and that the equipment functions as designed.

Allowable Values and/or Trip Setpoints are specified for each Function in the LCO. Nominal Trip Setpoints are also specified in the unit specific setpoint calculations. The nominal setpoints are selected to ensure that the setpoint measured by the surveillance procedure does not exceed the

(continued)

NUREG-1431 Markup Inserts
ITS SECTION 3.3.5 - LOSS OF POWER (LOP) DIESEL GENERATOR (DG) START INSTRUMENTATION

INSERT: B 3.3-144-01

on a 480 V bus.

Two undervoltage relays are provided on each 480 V bus for detecting a bus undervoltage. Either of the two relays is sufficient to satisfy requirements for the 480 V bus undervoltage Function because the failure the one remaining undervoltage relay could result in the failure of one DG to start and becasue there is redundancy in number of EDGs available. The two undervoltage relays are combined in a one-out-of-two logic per bus to generate an undervoltage signal. The allowable value and trip setpoint for this function is established in accordance with Reference 3. Actuation of these relays will trip the bus supply breaker, initiate load shedding, start the DG, and initiate load sequencing. There is no explicit time delay for this function because the undervoltage protection devices are induction type disc relays. Therefore, the time to actual trip will decrease as a function of voltage decrease below the setpoint.

Two degraded voltage relays are provided on each 480 V bus for detecting degraded bus voltage. The relays are combined in a two-out-of-two logic per bus (to prevent spurious actuation). The allowable value and trip setpoint for this function is established in accordance with Reference 3. Function actuation includes a time delay of ≤ 10 seconds if a coincident SI signal indicates accident conditions exist and a time delay of ≤ 45 seconds if no SI signal is generated (i.e., non-accident condition). These time delays ensure proper coordination with plant electrical transients (e.g. large motor starts, fast transfers, etc.). Actuation of these relays will trip the bus supply breaker, which will in turn actuate the undervoltage relays.

The LOP start actuation is described in FSAR, Section 8.2 (Ref. 1).

NUREG-1431 Markup Inserts
ITS SECTION 3.3.5 - LOSS OF POWER (LOP) DIESEL
GENERATOR (DG) START INSTRUMENTATION

INSERT: B 3.3-144-02

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 Allowable and bistable device, including their explicit uncertainties, is provided in Engineering Standards Manual IES-3B and IES-3B, Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3) (Ref. 3).

BASES

BACKGROUND

Trip Setpoints and Allowable Values (continued)

Allowable Value if the relay is performing as required. If the measured setpoint does not exceed the Allowable Value, the relay is considered OPERABLE. Operation with a Trip Setpoint less conservative than the nominal Trip Setpoint, but within the Allowable Value, is acceptable provided that operation and testing is consistent with the assumptions of the unit specific setpoint calculation. Each Allowable Value and/or Trip Setpoint specified is more conservative than the analytical limit assumed in the transient and accident analyses in order to account for instrument uncertainties appropriate to the trip function. These uncertainties are defined in the "Unit Specific RTS/ESFAS Setpoint Methodology Study" (Ref. 3).

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. The analyses assume a non-mechanistic DG loading, which does not explicitly account for each individual component of loss of power detection and subsequent actions.

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 2, 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The LOP DG start instrumentation channels satisfy Criterion 3 ~~of the NRC Policy Statement~~ of 10 CFR 50.36.

LCO

Insert: B3.3-146-01

The LCO for LOP DG start instrumentation requires that ~~[three] channels per bus of both the loss of voltage and degraded voltage functions shall~~ be OPERABLE in MODES 1, 2, 3, and 4 when the LOP DG start instrumentation supports safety systems associated with the ESFAS. In MODES 5 and 6, ~~the [three] channels must~~ be OPERABLE whenever the associated DG is required to be OPERABLE to ensure that the automatic start of the DG is available when needed. ~~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.~~

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 the required 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.

Because the required channels are specified on a per bus basis, the Condition may be entered separately for each bus as appropriate.

A Note has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of

(continued)

NUREG-1431 Markup Inserts
ITS SECTION 3.3.5 - LOSS OF POWER (LOP) DIESEL GENERATOR (DG) START INSTRUMENTATION

INSERT: B 3.3-146-01

1 channel per bus of undervoltage (480 V bus) Function and two channels per bus of the Degraded Voltage (480 V bus) Function must

BASES

ACTIONS (continued)

this Specification may be entered independently for each Function listed in the LCO. 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.

A.1

Condition A applies to the LOP DG start Function with one loss of voltage or degraded voltage channel per bus inoperable.

If one channel is inoperable, Required Action A.1 requires that channel to be placed in trip within 6 hours. With a channel in trip, the LOP DG start instrumentation channels are configured to provide a one-out-of-three logic to initiate a trip of the incoming offsite power.

A Note is added to allow bypassing an inoperable channel for up to 4 hours for surveillance testing of other channels. This allowance is made where bypassing the channel does not cause an actuation and where at least two other channels are monitoring that parameter.

The specified Completion Time and time allowed for bypassing one channel are reasonable considering the Function remains fully OPERABLE on every bus and the low probability of an event occurring during these intervals.

B.1

Condition B applies when more than one loss of voltage or more than one degraded voltage channel on a single bus is inoperable.

Required Action B.1 requires restoring all but one channel to OPERABLE status. The 1 hour Completion Time should allow ample time to repair most failures and takes into account the low probability of an event requiring an LOP start occurring during this interval.

(continued)

NUREG-1431 Markup Inserts
ITS SECTION 3.3.5 - LOSS OF POWER (LOP) DIESEL GENERATOR (DG) START INSTRUMENTATION

INSERT: B 3.3-147-01

Note that LCO 3.3.5 requires that only one of the two undervoltage (480 V bus) channels must be OPERABLE. Therefore, Condition A applies when there is no OPERABLE undervoltage (480 V bus) channel on one or more 480 volt vital bus(es).

INSERT: B 3.3-147-02

of 1 hour to restore an undervoltage (480 V bus) channels to OPERABLE status is needed because this Condition represents a loss of the undervoltage DG starting Function for the associated DG. The 1 hour delay in declaring the DG inoperable is acceptable because of

INSERT: B 3.3-147-03

one of the two required degraded voltage channels is inoperable on one or more 480 V vital bus.

INSERT: B 3.3-147-04

placing the inoperable channel in trip so that trip capability is restored to the 2 out of 2 logic used to initiate this Function.

BASES

ACTIONS (continued)

C.1

Condition C applies to each of the LOP DG start Functions when the Required Action and associated Completion Time for Condition A or B are not met.

Insert: B3.3-148-01

In these circumstances the Conditions specified in LCO 3.8.1, "AC Sources—Operating," or LCO 3.8.2, "AC Sources—Shutdown," for the DG made inoperable by failure of the LOP DG start instrumentation are required to be entered immediately. The actions of those LCOs provide for adequate compensatory actions to assure unit safety.

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.

(continued)

NUREG-1431 Markup Inserts
ITS SECTION 3.3.5 - LOSS OF POWER (LOP) DIESEL GENERATOR (DG) START INSTRUMENTATION

INSERT: B 3.3-148-01

Condition C also applies when two channels of Degraded Voltage Function inoperable in one or more buses. In this Condition, Function trip capability is lost even if one of the channels is placed in trip as specified in Required Action B.1.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.5.~~2~~ 1

SR 3.3.5.~~2~~ is the performance of a TADOT. This test is performed every [31 days]. 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.

SR 3.3.5.~~3~~ 2

SR 3.3.5.~~3~~ 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, as applicable ~~as shown in Reference 1~~.

Insert: B3.3-149-01

A CHANNEL CALIBRATION is performed every ~~[18] months, or~~ approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy.

The Frequency of ~~[18] months~~ is based on operating experience ~~and consistency with the typical industry refueling cycle~~ and is justified by the assumption of ~~an~~ the ~~[18] month~~ calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis. (Ref. 3)

REFERENCES

1. FSAR, Section ~~[8.3]~~. 8.2
2. FSAR, Chapter ~~[15]~~. 14.2
3. ~~Unit Specific RTS/ESFAS Setpoint Methodology Study~~.

Insert: B3.3-149-02

NUREG-1431 Markup Inserts
ITS SECTION 3.3.5 - LOSS OF POWER (LOP) DIESEL GENERATOR (DG) START INSTRUMENTATION

INSERT: B 3.3-149-01

every 24 months for the undervoltage relay and every 18 months for the degraded voltage relay

INSERT: B 3.3-149-02

3. Engineering Standards Manual IES-3 and IES-3B, Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3)

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.5:

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

PART 6:

Justification of Differences between

NUREG-1431 and IP3 ITS

JUSTIFICATION OF DIFFERENCES FROM NUREG-1431
ITS SECTION ITS SECTION 3.3.5 - LOSS OF POWER (LOP)
DIESEL GENERATOR (DG) START INSTRUMENTATION

RETENTION OF EXISTING REQUIREMENT (CURRENT LICENSING BASIS)

CLB.1 NUREG-1431, Rev 1, Section 3.3.6, was modified as needed to reflect the IP3 design and current licensing basis. A detailed description of the design, accident analysis assumptions, and Operability requirements are incorporated into the IP3 ITS Bases. These changes maintain the IP3 current licensing basis except as identified and justified in the CTS/ITS discussion of changes.

PLANT-SPECIFIC WORDING PREFERENCE OR MINOR EDITORIAL IMPROVEMENT

PA.1 Corrected typographical error or made a minor editorial improvement to improve clarity and ensure requirements are fully understood and consistently applied. There are no technical changes to requirements as specified in NUREG 1431, Rev. 1; therefore, this change is not a significant or generic deviation from NUREG 1431, Rev 1.

PLANT-SPECIFIC DIFFERENCE IN THE DESIGN OR DESIGN BASIS

DB.1 Design or implementation details are incorporated or revised as necessary to more precisely describe IP3 current design or practice. These changes are intended to describe the design, improve clarity, or ensure requirements are fully understood and consistently applied. Unless identified and described blow, these changes are self-explanatory. A detailed description of the design, accident analysis assumptions, and Operability requirements are incorporated into the IP3 ITS Bases. These changes maintain the IP3 current licensing basis except as identified and justified in the CTS/ITS discussion of changes.

DIFFERENCE BASED ON A GENERIC CHANGE TRAVELER FOR NUREG-1431

None

DIFFERENCE FOR ANY REASON OTHER THAN ABOVE

None

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.6:

"Containment Purge System and Pressure Relief Line Isolation Instrumentation"

PART 1:

Indian Point 3
Improved Technical Specifications and Bases

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 CORE ALTERATIONS,
During movement of 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

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. ---------NOTE--------- Only applicable in MODE 1, 2, 3, or 4. ---------- One or more pressure relief line isolation Functions with one or more 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 pressure relief line isolation valves made inoperable by isolation instrumentation.	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. ---------NOTE--------- Only applicable during CORE ALTERATIONS or movement of irradiated fuel assemblies within containment. ----------	C.1	Place and maintain containment purge system supply and exhaust valves in closed position.	Immediately
	OR		
One or more containment purge system isolation Functions with one or more automatic actuation trains inoperable.	C.2	Enter applicable Conditions and Required Actions of LCO 3.9.3, "Containment Penetrations," for containment purge system supply and exhaust isolation valves made inoperable by isolation instrumentation.	Immediately
OR			
Two radiation monitoring channels inoperable.			
OR			
Required Action and associated Completion Time for Condition A not met.			

SURVEILLANCE REQUIREMENTS

----------NOTE----------
Refer to Table 3.3.6-1 to determine which SRs apply for each Containment Purge System and Pressure Relief Line Isolation Function.

SURVEILLANCE		FREQUENCY
SR 3.3.6.1	Perform CHANNEL CHECK.	24 hours
SR 3.3.6.2	Perform ACTUATION LOGIC TEST.	31 days on a STAGGERED TEST BASIS
SR 3.3.6.3	Perform COT.	92 days
SR 3.3.6.4	----------NOTE---------- Verification of setpoint is not required. ---------- Perform TADOT.	24 months
SR 3.3.6.5	Perform CHANNEL CALIBRATION.	24 months

Table 3.3.6-1 (page 1 of 1)
Containment Purge System and Pressure Relief Line Isolation Instrumentation

	FUNCTION	REQUIRED CHANNELS	SURVEILLANCE REQUIREMENTS	TRIP SETPOINT
1.	Automatic Actuation Logic and Actuation Relays	2 trains	SR 3.3.6.2 SR 3.3.6.4	NA
2.	Gaseous Radiation Monitor (R-12)	1	SR 3.3.6.1 SR 3.3.6.3 SR 3.3.6.5	(b)
3.	Particulate Radiation Monitor (R-11)	1	SR 3.3.6.1 SR 3.3.6.3 SR 3.3.6.5	(b)
4.	ESFAS Function 1, Safety Injection, and ESFAS Function 2, Containment Spray (a)	Refer to LCO 3.3.2, ESFAS Instrumentation, Functions 1 and 2, for all initiation functions and requirements.		

(a) Only required in MODES 1, 2, 3 and 4 as specified in LCO 3.3.2.

(b) As specified in the IP3 Offsite Dose Calculation Manual.

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 Pressure Relief Line and the Containment Purge System. This action isolates the containment atmosphere from the environment to minimize releases of radioactivity in the event of an accident. The Containment Pressure Relief Line may be in use during reactor operation and the Containment Purge System may be in use with the reactor shutdown.

The Containment Purge System consists of the 36-inch containment purge supply and exhaust penetrations. The containment purge supply and exhaust penetrations each include two butterfly valves for isolation. The containment purge exhaust penetration includes two butterfly valves for isolation and can be aligned to discharge to the atmosphere through the plant vent either directly or through the Containment Purge Filter System (i.e., a filter bank with roughing, HEPA and charcoal filters).

The Containment Purge System is isolated when in Modes 1, 2, 3 and 4 in accordance with requirements established in LCO 3.6.3, Containment Isolation Valves. In Modes 5 and 6, the Containment Purge System may be used for containment ventilation. When open, the Containment Purge System isolation valves are automatically closed when high radiation levels are detected by the Containment Air Particulate Monitor (R-11) or Containment Radioactive Gas Monitor (R-12).

The Containment Purge System isolation capability is not the primary method for ensuring that 10 CFR 100 limits are not exceeded during a fuel handling event (Ref. 1). As specified in LCO 3.9.3, Containment Penetrations, the Containment Purge System is aligned to discharge through the Containment Purge Filter System during CORE ALTERATIONS or movement of irradiated fuel until the reactor has been shutdown for at least 550 hours. Purge path filtration during the first 550 hours following reactor shutdown ensures that the dose limit for a fuel handling

BASES

BACKGROUND (Continued)

accident of 75 rem to the thyroid (25 percent of the 10 CFR Part 100 limit of 300 rem) at the Exclusion Area Boundary (EAB) (i.e., site boundary) is not exceeded (Ref. 2).

The Containment Pressure Relief Line (i.e., Containment Vent) consists of a single 10-inch containment vent line that is used to handle normal pressure changes in the Containment when in Modes 1, 2, 3 and 4. The Containment Pressure Relief Line is equipped with three quick-closing butterfly type isolation valves, one inside and two outside the containment which isolate automatically as part of Safety Injection ESFAS signal (LCO 3.3.2, Function 1) and Containment Spray ESFAS signal (LCO 3.3.2, Function 2). Automatic isolation of the Containment Pressure Relief Line is also initiated when high radiation levels are detected by the Containment Air Particulate Monitor (R-11) or Containment Radioactive Gas Monitor (R-12).

The Containment Pressure Relief Line is isolated during CORE ALTERATIONS or movement of irradiated fuel during the first 550 hours following reactor shutdown as specified in LCO 3.9.3. Although the Containment Pressure Relief Line discharges to the atmosphere via the Containment Auxiliary Charcoal Filter System (i.e., a filter bank with roughing, HEPA and charcoal filters), the Containment Auxiliary Charcoal Filter System is not required to be tested in accordance with Specification 5.5.10, Ventilation Filter Test Program.

Both the Containment Purge supply and exhaust isolation valves (FCV-1170, FCV-1171, FCV-1172, and FCV-1173) and the containment pressure relief isolation valves (PCV-1190, PCV-1191, and PCV-1192) close when high radiation levels are detected by the Containment Air Particulate Monitor (R-11) or Containment Radioactive Gas Monitor (R-12). The Safety Injection ESFAS signal (LCO 3.3.2, Function 1) 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 Specification requirements, containment purge and containment pressure relief are also isolated when high radiation levels are detected in the plant vent.

BASES

APPLICABLE SAFETY ANALYSES

In MODE 1, 2, 3 or 4, Containment Purge System automatic isolation capability is not required because the Containment Purge System is isolated in accordance with the requirements of LCO 3.6.3, Containment Isolation Valves.

During CORE ALTERATIONS or movement of irradiated fuel in the containment, Containment Purge System automatic isolation capability is required because it provides for automatic containment isolation in response to a fuel handling accident. As specified in LCO 3.9.3, Containment Penetrations, the Containment Purge System is aligned to discharge through the Containment Purge Filter System during CORE ALTERATIONS or movement of irradiated fuel until the reactor has been shutdown for at least 550 hours. Purge path filtration during the first 550 hours following reactor shutdown ensures that the dose limit for a fuel handling accident of 75 rem to the thyroid (25 percent of the 10 CFR Part 100 limit of 300 rem) at the EAB (i.e., site boundary) is not exceeded (Ref. 2). Although Containment Purge System isolation capability is not required to meet 10 CFR Part 100 limits during a fuel handling accident, this function provides a backup to the filtering function assumed in the analysis and is required to provide containment isolation following the event.

In MODE 1, 2, 3 or 4, Containment Pressure Relief Line automatic isolation capability is required as part of the containment isolation function initiated by the Engineered Safety Feature Actuation System (ESFAS) Instrumentation required by LCO 3.3.2. Containment Pressure Relief Line automatic isolation when high radiation levels are detected by the Containment Air Particulate Monitor (R-11) or Containment Radioactive Gas Monitor (R-12) provides a backup to the closure initiated by the ESFAS system.

During CORE ALTERATIONS or movement of irradiated fuel in the containment, Containment Pressure Relief Line automatic isolation capability is not required because the Containment Pressure Relief Line is isolated as specified in LCO 3.9.3. The Containment Pressure Relief Line is isolated because the fuel

BASES

APPLICABLE SAFETY ANALYSES (continued)

handling accident analysis (References 1 and 2) credits filtration and not automatic isolation to ensure 10 CFR 100 limits are met. The Containment Auxiliary Charcoal Filter System which filters the Containment Pressure Relief Line is not required to be tested in accordance with Specification 5.5.10, Ventilation Filter Test Program.

The containment purge system and pressure relief line isolation instrumentation satisfies Criterion 3 of 10 CFR 50.36.

LCO

The LCO requirements ensure that the instrumentation listed in Table 3.3.6-1, is OPERABLE. This instrumentation is required to initiate automatic isolation of the Containment Purge System and the Containment Pressure Relief Line.

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.

Automatic Actuation Logic and Actuation Relays are required to be OPERABLE to support the Operability of all of the required functions that isolate the containment purge system and pressure relief line (i.e., gaseous and particulate radiation monitors (R-11 and R-12) and ESFAS SI and containment spray initiation signals). The term Automatic Actuation Logic and Actuation Relays applies to those portions of the circuit that are: 1) common to more than one channel in one train of a single function (i.e., the automatic actuation logic); or, 2) the initiating relay contacts in one train responsible for actuating the equipment and which are common to more than one channel of a single function and more than one function (i.e., the actuation relays). There are two trains of automatic actuation logic and actuation relays for the containment purge system and pressure relief line.

BASES

LCO (continued)

If one or more of the SI or Containment Spray Functions becomes inoperable in such a manner that only the Containment Purge Isolation Function is affected, the Conditions applicable to their SI and Containment Spray Functions need not be entered. The less restrictive Actions specified for inoperability of the Containment Purge System and Pressure Relief Line Isolation Functions specify sufficient compensatory measures for this case.

2. Containment Radiation Monitors

The LCO specifies two required channels of radiation monitors to ensure that the radiation monitoring instrumentation necessary to initiate Containment Purge System Isolation remains OPERABLE. The requirement for two channels is satisfied by the Containment Air Particulate Monitor (R-11) and the Containment Radioactive Gas Monitor (R-12). Allowable values and setpoints for these Functions are specified in the IP3 Offsite Dose Calculation Manual (Ref. 3).

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. ESFAS Function 1, Safety Injection, and ESFAS Function 2, Containment Spray Monitors

Refer to LCO 3.3.2, Functions 1 and 2, for all initiating Functions and requirements.

APPLICABILITY

In MODE 1, 2, 3 or 4, Containment Purge System automatic isolation capability is not required because the Containment Purge System is isolated in accordance with the requirements of LCO 3.6.3, Containment Isolation Valves.

BASES

APPLICABILITY (continued)

During CORE ALTERATIONS or movement of irradiated fuel in the containment, Containment Purge System automatic isolation Function 1, Automatic Actuation Logic and Actuation Relays, and Function 2, Containment Radiation, are required to be OPERABLE to ensure Containment Purge System isolation in response to a fuel handling accident.

In MODE 1, 2, 3 or 4, Containment Pressure Relief Line automatic isolation Function 1, Automatic Actuation Logic and Actuation Relays, and Function 3, ESFAS Safety Injection and ESFAS Containment Spray, are required as part of the containment isolation function initiated by the Engineered Safety Feature Actuation System (ESFAS) Instrumentation required by LCO 3.3.2. Containment Pressure Relief Line automatic isolation Function 2, Containment Radiation, is required as a backup to the closure initiated by the ESFAS system.

During CORE ALTERATIONS or movement of irradiated fuel in the containment, Containment Pressure Relief Line automatic isolation capability is not required because the Containment Pressure Relief Line is isolated as specified in LCO 3.9.3.

While in MODES 5 and 6 without fuel handling in progress, the containment purge system and pressure relief line isolation instrumentation need not be OPERABLE since the potential for radioactive releases is minimized and operator action is sufficient to ensure post accident offsite doses are maintained within the limits of 10 CFR 100.

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

BASES

ACTIONS (continued)

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.

A.1

Condition A applies to the failure of either the R-11 or the R-12 radiation monitor channel. Since the two containment radiation monitors measure different parameters, failure of a single channel may result in delay of the radiation monitoring Function for certain events. However, 7 days is allowed to restore the affected channel because the containment radiation monitoring function is not the primary method or ensuring that 10 CFR limits are not exceed.

B.1

Condition B applies to all Containment Pressure Relief Line Isolation Functions and addresses the train orientation of 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.

BASES

ACTIONS (continued)

C.1 and C.2

Condition C applies to all Containment Purge System Isolation Functions and addresses the train orientation of 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 to place and maintain Containment Purge System 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 CORE ALTERATIONS and during movement of 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 System and Pressure Relief Line 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 a CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION. 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 limits.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.6.1 (continued)

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 3.3.6.2

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

A COT is performed every 92 days on each radiation monitoring channel to ensure the entire channel will perform the intended Function. This test verifies the capability of the instrumentation to provide the containment purge system and pressure relief line isolation. The setpoint shall be left consistent with the current unit specific calibration procedure tolerance.

SR 3.3.6.4

SR 3.3.6.4 is the performance of a TADOT. This test is a check every 24 months that includes actuation of the end device (i.e., valve cycles, etc.).

The test also includes trip devices that provide actuation signals directly to the actuation instrumentation, bypassing the analog process control equipment. The SR is modified by a Note

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.6.4 (continued)

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 3.3.6.5

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 specified in the IP3 Offsite Dose Calculation Manual (Ref. 3).

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

REFERENCES

1. FSAR Chapter 14.

2. Safety Evaluation Report (SER) for IP3 Amendment 175.

3. IP3 Offsite Dose Calculation Manual.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.6:

"Containment Purge System and Pressure Relief Line Isolation Instrumentation"

PART 2:

CURRENT TECHNICAL SPECIFICATION PAGES

Annotated to show differences between CTS and ITS

CTS pages and associated TSCRs annotated for this ITS Specification :

CTS Page No.	Effective Amendment	Annotated Amendment	TSCR No.	TSCR Description	ITS Status of TSCR
3.5-6	154	154	No TSCRs	No TSCRs for this Page	N/A
T 3.5-4(2)	151	151	No TSCRs	No TSCRs for this Page	N/A
3.8-2	175	175	No TSCRs	No TSCRs for this Page	N/A
3.8-3	114	114	No TSCRs	No TSCRs for this Page	N/A
T 4.1-1(2)	169	169	No TSCRs	No TSCRs for this Page	N/A
T 4.1-1(3)	168 TSCR 98-043	168 TSCR 98-043	IPN 98-043	Instrument Channel Surveillance Intervals Extended to 24 Months	Incorporated
4.5-1	142	142	No TSCRs	No TSCRs for this Page	N/A
4.5-2	172 TSCR 98-043	172 TSCR 98-043	IPN 98-043	Instrument Channel Surveillance Intervals Extended to 24 Months	Incorporated

A.1

Feedwater Line Isolation

The feedwater lines are isolated upon actuation of the Safety Injection System in order to prevent excessive cooldown of the reactor coolant system. This mitigates the effect of an accident such as steam break which in itself causes excessive coolant temperature cooldown. Feedwater line isolation also reduces the consequences of a steam line break inside the containment, by stopping the entry of feedwater.

Containment Vent and Purge

The containment vent and purge valves are isolated upon actuation of the Safety Injection System, Containment Spray System, or upon receipt of a high containment radiation signal. In the event of an accident, this action prevents a continuous radioactive release via the Containment Vent and Purge System.

Allowable Values

Table 3.5-1 provides the "allowable values" for Engineered Safety Features instrumentation. The "allowable values" represent the limit placed on the "as-found" condition for an instrument loop. If the "as-found" condition measured during calibration is within the "allowable value," the instrument loop will satisfy the system and safety requirements. [6]

1. The Hi-Level containment pressure value is about 10% of containment design pressure. Initiation of Safety Injection protects against loss of coolant[2] or steam line break[3] accidents as discussed in the safety analysis.

2. The Hi-Hi Level containment pressure value is about 50% of containment design pressure. Initiation of Containment Spray and Steam Line Isolation protects against large loss of coolant[2] or steam line break accidents[3] as discussed in the safety analysis.

3. The pressurizer low pressure value is substantially below system operating pressure limits. However, it is sufficiently high to protect against a loss of coolant accident as shown in the safety analysis[2]. The trip is bypassed below 2000 psig to prevent inadvertent actuation of the Engineered Safeguards when the reactor is shutdown.

Pressure Relief — A.3

TABLE 3.5-4 (Sheet 2 of 2)

No.	FUNCTIONAL UNIT	1 NO. OF CHANNELS	2 NO. OF CHANNELS TO TRIP	3 MIN. OPERABLE CHANNELS	4 MIN. DEGREE OF REDUNDANCY	5 OPERATOR ACTION IF CONDITIONS IN COLUMN 3 OR 4 CANNOT BE MET
3.	FEEDWATER LINE ISOLATION					
a.	Safety Injection	See	Item	No. 1	of	Table 3.5-3
4.	CONTAINMENT VENT AND PURGE					
a.	Containment Radioactivity High (R11 and R12 monitor)	2	1	1	0 (2)	close all containment vent and purge valves when above cold shutdown (A.3) (A.5) (LA.1) (M.1)
5.	PLANT EFFLUENT RADIOIODINE/PARTICULATE SAMPLING (sample line common with monitor R13)	1	NA	1	0	(see note 3)
6.	Main Steam Line Radiation Monitors	1/line	NA	1/line	0	(see note 3)
7.	Wide Range Plant Vent Monitor (R27)	1	NA	1	0	(see note 3)

SEE ITS 3.3.2

LCO 3.3.6 Req Act A.1

Applicability

SEE CTS MASTER MARKUP

NOTES

1. If the conditions of Columns 3 or 4 cannot be met, the reactor shall be placed in the hot shutdown condition, utilizing normal operating procedures, within 4 hours of the occurrence. If the conditions are not met within 24 hours of the occurrence, the reactor shall be placed in the cold shutdown condition, or the alternate condition if applicable, within an additional 24 hours.

2. Main steam isolation valves may be closed in lieu of going to cold shutdown if the circuitry associated with closing the valves is the only portion inoperable.

3. If the plant vent sampling capability, the wide-range vent monitor or the main steam line radiation monitors is/are: determined to be inoperable when the reactor is above the cold shutdown condition, then restore the sampling/monitoring capability within 72 hours or:
   a) Initiate a pre-planned alternate sampling/monitoring capability as soon as practical, but no later than 72 hours after identification of the failures. If the capability is not restored to operable status within 7 days, then,
   b) Submit a Special Report to the NRC pursuant to Technical Specification 6.9.2 within 14 days following the event outlining the action taken, the cause of the inoperability and the plans and schedule for restoring the system.

Add Actions Note: Separate Condition entry — A.4

A.3

SR 3.3.6.3
SR 3.3.6.4

~~8.~~ The containment vent and purge system, including the radiation monitors which initiate isolation, shall be tested and verified to be operable ~~within 100 hours prior to refueling operations~~ L.1

SEE CTS MASTER MARKUP

9. No movement of irradiated fuel in the reactor shall be made until the reactor has been subcritical for at least 145 hours. In addition, movement of fuel in the reactor before the reactor has been subcritical for equal to or greater than 421* hours will necessitate operation of the Containment Building Vent and Purge System through the HEPA filters and charcoal absorbers. For this case operability of the Containment Building Vent and Purge System shall be established in accordance with Section 4.13 of the Technical Specifications. In the event that more than 76 assemblies are to be discharged from the reactor, those assemblies in excess of 76 shall not be discharged earlier than 267 hours after shutdown.

10. Whenever movement of irradiated fuel is being made, the minimum water level in the area of movement shall be maintained 23 feet over the top of the reactor pressure vessel flange.

11. Hoists or cranes utilized in handling irradiated fuel shall be dead- load tested before movement begins. The load assumed by the hoists or cranes for this test must be equal to or greater than the maximum load to be assumed by the hoists or cranes during the refueling operation. A thorough visual inspection of the hoists or cranes shall be made after the deadload test and prior to fuel handling. A test of interlocks and overload cutoff devices on the manipulator shall also be performed.

12. The fuel storage building emergency ventilation system shall be operable whenever irradiated fuel is being handled within the fuel storage building. The emergency ventilation system may be inoperable when irradiated fuel is in the fuel storage building, provided irradiated fuel is not being handled and neither the spent fuel cask nor the cask crane are moved over the spent fuel pit during the period of inoperability.

13. To ensure redundant decay heat removal capability, at least two of the following requirements shall be met:

* Movement of irradiated VANTAGE + fuel assemblies before the reactor has been subcritical for ≥550 hours requires operation of the Containment Building Vent and Purge System through the HEPA filters and charcoal adsorbers.

Amendment No. ~~13~~, ~~30~~, ~~34~~, ~~53~~, ~~69~~, 72, ~~90~~, ~~173~~, 175

SEE CTS MASTER MARKUP

a. No. 31 residual heat removal pump and heat exchanger, together with their associated piping and valves are operable.

b. No. 32 residual heat removal pump and heat exchanger, together with their associated piping and valves are operable.

c. The water level in the refueling cavity above the top of the reactor vessel flange is equal to or greater than 23 feet.

Req. Act C.1, C.2

B. If any of the specified limiting conditions for refueling are not met, refueling shall cease until the specified limits are met, and no operations which may increase the reactivity of the core shall be made. A.6

SEE CTS MASTER MARKUP

C. During fuel handling and storage operations, the following conditions shall be met:

1. Radiation levels in the spent fuel storage area shall be monitored continuously whenever there is irradiated fuel stored therein. If the monitor is inoperable, a portable monitor may be used.

2. The spent fuel cask shall not be moved over any region of the spent fuel pit which contains irradiated fuel. Additionally, if the spent fuel pit contains irradiated fuel, no loads in excess of 2,000 pounds shall be moved over any region of the spent fuel pit.

3. During periods of spent fuel cask or fuel storage building cask crane movement over the spent fuel pit, or during periods of spent fuel movement in the spent fuel pit when the pit contains irradiated fuel, the pit shall be filled with borated water at a concentration of >1000 ppm.

4. Whenever movement of irradiated fuel in the spent fuel pit is being made, the minimum water level in the area of movement shall be maintained 23 feet over the top of irradiated fuel assemblies seated in the storage rack.

TABLE 4.1-1 (Sheet 2 of 6)

	Channel Description	Check	Calibrate	Test	Remarks
SEE CTS MASTER MARKUP	8. 6.9 KV Voltage	N.A.	18M	Q	Reactor protection circuits only
	6.9 KV Frequency	N.A.	24M	Q	Reactor protection circuits only
	9. Analog Rod Position	S	24M	M	
	10. Steam Generator Level	S	24M	Q	
	11. Residual Heat Removal Pump Flow	N.A.	24M	N.A.	
	12. Boric Acid Tank Level	S	24M	N.A.	Bubbler tube rodded during calibration
	13. Refueling Water Storage Tank Level				
	a. Transmitter	W	18M	N.A.	Low level alarm
	b. Indicating Switch	W	6M	N.A.	Low level alarm
	14a. Containment Pressure - narrow range	S	24M	Q	
	14b. Containment Pressure - wide range	M	18M	N.A.	High and High-High
	15. Process and Area Radiation Monitoring:				
	a. Fuel Storage Building Area Radiation Monitor (R-5)	D	24M	Q	
SR 3.3.6.1 SR 3.3.6.3 SR 3.3.6.5	b. Vapor Containment Process Radiation Monitors (R-11 and R-12)	D SR 3.3.6.1	24M SR 3.3.6.5	Q SR 3.3.6.3	
SEE CTS MASTER MARKUP	c. Vapor Containment High Radiation Monitors (R-25 and R-26)	D	24M	Q	
	d. Wide Range Plant Vent Gas Process Radiation Monitor (R-27)	D	24M	Q	

Amendment No. 8, 38, 65, 68, 74, 93, 107, 125, 137, 140, 144, 148, 150, 154, 169

TABLE 4.1-1 (Sheet 3 of 6)

Channel Description	Check	Calibrate	Test	Remarks
e. Main Steam Lines Process Radiation Monitors (R-62A, R-62B, R-62C, and R-62D)	D	24M	Q	
f. Gross Failed Fuel Detectors (R-63A and R-63B)	D	24M	Q	
16. Containment Water Level Monitoring System:				
a. Containment Sump	N.A.	24M	N.A.	Narrow Range, Analog
b. Recirculation Sump	N.A.	24M	N.A.	Narrow Range, Analog
c. Containment Water Level	N.A.	24M	N.A.	Wide Range
17. Accumulator Level and Pressure	S	24M	N.A.	
18. Steam Line Pressure	S	24M	Q	
19. Turbine First Stage Pressure	S	24M	Q	
20a. Reactor Trip Relay Logic	N.A.	N.A.	TM	
20b. ESF Actuation Relay Logic	N.A.	N.A.	TM	
21. Turbine Trip Low Auto Stop Oil Pressure	N.A.	24M	N.A.	
22. DELETED	DELETED	DELETED	DELETED	
23. Temperature Sensor in Auxiliary Boiler Feedwater Pump Building	N.A.	N.A.	18M	
24. Temperature Sensors in Primary Auxiliary Building				
a. Piping Penetration Area	N.A.	N.A.	24M	
b. Mini-Containment Area	N.A.	N.A.	24M	
c. Steam Generator Blowdown Heat Exchanger Room	N.A.	N.A.	24M	

SEE CTS MASTER MARKUP

T 3.3.6-1, -43

SEE CTS MASTER MARKUP

4.5 TESTS FOR ENGINEERED SAFETY FEATURES AND AIR FILTRATION SYSTEMS

A.2

~~Applicability~~

~~Applies to testing of the Safety Injection System, the Containment Spray System, the Hydrogen Recombiner System, and the Air Filtration Systems.~~

~~Objective~~

~~To verify that the subject systems will respond promptly and perform their design functions, if required.~~

Specification

A. SYSTEM TESTS

1. Safety Injection System

SR3.3.6.4

a. System tests shall be performed at least once per 24 months*. With the Reactor Coolant System pressure less than or equal to 350 psig and temperature less than or equal to 350°F, a test safety injection signal will be applied to initiate operation of the system. The safety injection and residual heat removal pumps are made inoperable for this test.

b. The test will be considered satisfactory if control board indication and visual observations indicate that all components have received the safety injection signal in the proper sequence and timing, that is, the appropriate pump breakers shall have opened and closed, and the appropriate valves shall have completed their travel.

SEE CTS MASTER LIST OF

c. Conduct a flow test of the high head safety injection system after any modification is made to either its piping and/or valve arrangement.

d. Verify that the mechanical stops on Valves 856 A, C, D, E, F, H, J and K are set at the position measured and recorded during the most recent ECCS operational flow test or flow tests performed in accordance with (c) above. This surveillance procedure shall be performed following any maintenance on these valves or their associated motor operators and at a convenient outage if the position of the mechanical stops have not been verified in the preceding three months.

* The time delay relays will be tested at intervals no greater than 22.5 months (18 months + 25%).

2. Containment Spray System

SR 3.3.6.4

a. System tests shall be performed at least once per 24 months. The tests shall be performed with the isolation valves in the spray supply lines at the containment and the spray additive tank isolation valves blocked closed. Operation of the system is initiated by tripping the normal actuation instrumentation.

b. The spray nozzles shall be checked for proper functioning at least every five years.

SEE CTS MASTER MARKUP

c. The tests will be considered satisfactory if visual observations indicate all components have operated satisfactorily.

3. Containment Hydrogen Monitoring Systems

a. Containment hydrogen monitoring system tests shall be performed at intervals no greater than six months. The tests shall include drawing a sample from the fan cooler units.

b. The above tests will be considered satisfactory if visual observations and control panel indication indicate that all components have operated satisfactorily.

Amendment No. 101, 118, 128, 129, 172, TSCR 98-043

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.6:

"Containment Purge System and Pressure Relief Line Isolation Instrumentation"

PART 3:

DISCUSSION OF CHANGES

Differences between CTS and ITS

DISCUSSION OF CHANGES
ITS SECTION 3.3.6 - CONTAINMENT PURGE AND
PRESSURE RELIEF ISOLATION INSTRUMENTATION

ADMINISTRATIVE

A.1 In the conversion of the Indian Point Unit 3 Current Technical Specifications (CTS) to the plant specific Improved Technical Specifications (ITS) certain wording preferences or conventions are adopted which do not result in technical changes (either actual or interpretational). Additionally, editorial changes, reformatting, and revised numbering are adopted to make ITS consistent with the conventions in NUREG-1431, Standard Technical Specifications, Westinghouse Plants, Rev. 1, i.e., the improved Standard Technical Specifications.

The CTS Bases are deleted and replaced with comprehensive ITS Bases designed to support interpretation and implementation of the associated Technical Specifications. The Bases explain, clarify, and document the reasons (i.e., bases) for the associated Technical Specifications, and reflect the IP3 plant specific design, analyses, and licensing basis. In accordance with 10 CFR 50.36(a), the ITS Bases are included with the proposed ITS conversion application; however, deletion of the CTS Bases and the adoption of the ITS Bases is an administrative change with no impact on safety.

A.2 CTS Limiting Conditions for Operation (LCOs) and Surveillance Requirements (SRs) include statements of the objective and the applicability. The CTS statements of objective and applicability are deleted because these statements do not establish any requirements and do not provide any guidance for the application of CTS requirements. Therefore, deletion of these statements has no significant adverse impact on safety.

A.3 CTS 3.6, CTS 3.8, CTS Table 4.1-1 and CTS 4.13 use the term containment vent to describe the containment penetration that includes pressure relief isolation valves PCV-1190, PCV-1191, and PCV-1192 and which is used to handle the normal pressure changes in the Containment during reactor power operation. FSAR 5.3.2.5 and control room labeling identify this system as the Containment Pressure Relief Line. ITS will use the term Containment Pressure Relief Line for this system to be

consistent with FSAR 5.3.2.5 and control room labeling. This is an administrative change with no adverse impact on safety because there is no change to the existing requirements.

A.4 The Actions for ITS 3.3.6, Containment Purge and Pressure Relief Isolation Instrumentation, are preceded by a Note that specifies: "Separate Condition entry is allowed for each channel." This allowance provides explicit recognition that the ITS is designed to allow completely separate re-entry into any Condition for each train and/or channel addressed by the Condition. This includes separate tracking of Completion Times based on this re-entry. This allowance is consistent with an unstated assumption in the CTS. Therefore, the addition of this Note is an administrative change with no impact on safety.

A.5 CTS 3.8.C.8 implies that both the Containment Building Vent (i.e., pressure relief line, See ITS 3.3.6, DOC A.3) and Purge System actuation instrumentation must be Operable during refueling operations. CTS Table 3.5-4, Item 4, implies, based on the Required Action, that both the Containment Building Vent and Purge Systems must be Operable above cold shutdown.

ITS 3.3.6, in conjunction with LCO 3.6.3 and LCO 3.9.3, clarify the Applicability requirements for the Containment Purge System isolation and the Containment Pressure Relief Line isolation as follows:

> In Modes 1, 2, 3 or 4, **Containment Purge System** automatic isolation capability is not required because the Containment Purge System is isolated in accordance with the requirements of LCO 3.6.3, Containment Penetrations.
>
> During CORE ALTERATIONS or movement of irradiated fuel in the containment, **Containment Purge System** automatic isolation Function 1, Automatic Actuation Logic and Actuation Relays, and Function 2, Containment Radiation, are required to be OPERABLE to ensure Containment Purge System isolation in response to a fuel handling accident.

In Modes 1, 2, 3 or 4, **Containment Pressure Relief Line** automatic isolation Function 1, Automatic Actuation Logic and Actuation Relays, and Function 3, ESFAS Safety Injection and ESFAS Containment Spray, are required as part of the containment isolation function initiated by the Engineered Safety Feature Actuation System (ESFAS) Instrumentation required by LCO 3.3.2. Containment Pressure Relief Line automatic isolation Function 2, Containment Radiation, is required as a backup to the closure initiated by the ESFAS system.

During CORE ALTERATIONS or movement of irradiated fuel in the containment, **Containment Pressure Relief Line** automatic isolation capability is not required because the Containment Pressure Relief Line is isolated as specified in LCO 3.9.3.

This clarification of the existing requirements clarifies that both the Containment Purge System isolation and the Containment Pressure Relief Line isolation function must be Operable at all times or the affected isolation valves must be shut. This is an administrative change with no adverse impact on safety because it is a reasonable interpretation of the equivalent CTS requirement.

A.6 CTS Table 3.5-4, Item 4, requires that all containment vent and purge valves immediately if the required channel is not Operable. LCO 3.3.6, Required Actions B.1 and C.1, maintain this requirement by directing entry into the Conditions and Required Actions for an inoperable isolation valve if the isolation actuation instrumentation is not Operable. This is an administrative change with no adverse impact on safety because it is a reasonable interpretation of the equivalent CTS requirement.

MORE RESTRICTIVE

M.1 CTS Table 3.5-4, Item 4, requires 1 operable channel of the Containment Radioactivity High (R-11 and R-12 monitors) with a minimum degree of redundancy of zero. This combination creates a requirement for 1 channel of this function with a required action to close all containment

vent and purge valves immediately if the required channel is not Operable.

LCO 3.3.6 requires that 2 channels (i.e., both the R-11 and R-12 monitor) are Operable. In conjunction with this change, LCO 3.3.6, Required Action A.1, is added to require that if one of the two required channels is inoperable, it must be restored to Operable within 7 days. This change is needed because the R-11 and R-12 containment radiation monitors measure different parameters and failure of a single channel may result in loss of the radiation monitoring Function for certain events. Although Containment Purge System isolation capability is not required to meet 10 CFR Part 100 limits during a fuel handling accident, this function provides a backup to the filtering function assumed in the analysis and is required to provide containment isolation following the event. This change (i.e., 7 days to restore an inoperable channel) is acceptable because the containment radiation monitoring function is not the primary method or ensuring that 10 CFR limits are not exceed. Specifically, purge path filtration during the first 550 hours following reactor shutdown ensures that the dose limit for a fuel handling accident at the EAB is not exceeded. Therefore, this change has no significant adverse impact on safety.

LESS RESTRICTIVE

L.1 CTS 3.8.A.8 requires that the Containment Building Vent and Purge System, including radiation monitors that initiate isolation, must be tested and verified to be operable within 100 hours prior to refueling operations. ITS SR 3.3.6.3 and ITS SR 3.3.6.4 maintain this requirement for periodic verification by requiring a Channel Operational Test every 92 days and a Trip Actuating Device Operational Test every 24 months.

This change is needed because ITS Surveillance tests are performed at the periodic frequency only and are not required to be repeated prior to a specific event, such as refueling. The normal periodic surveillance frequencies are established to provide adequate assurance of operability. ITS SR 3.0.4 ensures that the required surveillances have been performed within the normal specified interval prior to entering an applicable mode or condition.

This change is acceptable because the requirement that the Containment Building Vent and Purge isolation function is Operable during fuel movement and Core Alterations is unchanged. Elimination of the requirement to perform this verification within 100 hours prior to an activity is not significant because the normal periodic Surveillance Frequency is established to provide adequate assurance that requirements are being met. The 92-day Frequency for the COT and the 24 month Frequency for the TADOT ensure that the SR is performed at the start of each refueling and this Frequency is sufficient to provide a high degree of assurance that the valves will function as required throughout a refueling outage. Therefore, this change has no adverse impact on safety.

REMOVED DETAIL

LA.1 CTS Section 3.5, Tables 3.5-2, 3.5-3 and 3.5-4, Columns 1 and 2, identify the number of channels and the channels required to trip for each RPS and ESFAS Function. ITS LCO 3.3.1, LCO 3.3.2, LCO 3.3.3, LCO 3.3.5 and LCO 3.3.6 require that these Functions be Operable but do not provide system design details. This is acceptable because this design information is incorporated into the minimum requirements and ITS specifies the minimum requirements for Operability.

This change is acceptable because ITS LCO 3.3.1, LCO 3.3.2, LCO 3.3.3, LCO 3.3.5 and LCO 3.3.6 maintain the existing requirements for the Operability of these instruments (except as identified and justified in this discussion of change); therefore, there is no change to the existing requirements and no change to the level of safety of facility operation.

This change, which allows the description of the design of instrument functions to be maintained in the FSAR and the detailed description of the requirements for Operability of these functions to be maintained in the ITS Bases, is consistent with the approach used in NUREG-1431 for all Limiting Conditions for Operation (LCOs). This approach is acceptable because the requirements of 10 CFR 50.59, Changes, Tests and Experiments, and ITS 5.5.13, Technical Specifications (TS) Bases Control

Program, are designed to assure that changes to the FSAR and ITS Bases do not result in changes to the Technical Specification requirements and do not result in significant increases in the probability or consequences of accidents previously evaluated, do not create the possibility of a new or different kind of accident, and do not result in a significant reduction in a margin of safety. Additionally, IP3 programs that implement FSAR changes in accordance with 10 CFR 50.59 and ITS Bases changes in accordance with ITS 5.5.13 require periodic submittal of FSAR and Bases changes to the NRC for review.

This change is a less restrictive administrative change with no impact on safety because no requirements are being deleted from Technical Specifications and an appropriate change control process and an appropriate level of regulatory oversight are maintained for the information being relocated out of the Technical Specifications.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.6:

"Containment Purge System and Pressure Relief Line Isolation Instrumentation"

PART 4:

No Significant Hazards Considerations for Changes between CTS and ITS that are Less Restrictive

No Significant Hazard Considerations for Changes that are Administrative, More Restrictive, and Removed Details are the same for all Packages. A Copy is included at the end of the Package.

NO SIGNIFICANT HAZARDS EVALUATION
ITS SECTION 3.3.6 - CONTAINMENT PURGE AND
PRESSURE RELIEF ISOLATION INSTRUMENTATION

LESS RESTRICTIVE
("L.1" Labeled Comments/Discussions)

New York Power Authority has evaluated the proposed Technical Specification change identified as "Less Restrictive" in accordance with the criteria set forth in 10 CFR 50.92, and has determined that the proposed change does not involve a significant hazards consideration. The bases for the determination that the proposed change does not involve a significant hazards consideration are discussed below.

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

   This change deletes the requirement to perform testing and verify operability of the containment purge and pressure relief isolation instrumentation within 100 hours prior to refueling operations. Surveillance tests are performed at the normal periodic frequency only and these tests are not required to be repeated prior to a specific event, such as refueling. The normal periodic surveillance frequencies are established to provide adequate assurance of operability. ITS SR 3.0.4 ensures that the required surveillances have been performed within the normal specified interval prior to entering an applicable mode or condition.

   This change will not result in a significant increase in the probability of an accident previously evaluated because the isolation instrumentation is not assumed as the initiator of any accident previously evaluated.

   This change will not result in a significant increase in the consequences of an accident previously evaluated because the requirement that the Containment Building Vent and Purge isolation function is Operable during fuel movement and Core Alterations is unchanged. Elimination of the requirement to perform this verification within 100 hours prior to an activity is not significant because the normal periodic Surveillance Frequency is established to provide adequate assurance that requirements are being met. The 92-day Frequency for the COT and the 24 month Frequency for the TADOT ensure that the SR is

performed at the start of each refueling and this Frequency is sufficient to provide a high degree of assurance that the valves will function as required throughout a refueling outage. Therefore, this change has no adverse impact on safety

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

   The proposed change will not involve any physical changes to systems, structures, or components, or involve a change in normal plant operation. Therefore, it will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   This change does not involve a significant reduction in a margin of safety because the requirement that the Containment Building Vent and Purge isolation function is Operable during fuel movement and Core Alterations is unchanged. Elimination of the requirement to perform this verification within 100 hours prior to an activity is not significant because the normal periodic Surveillance Frequency is established to provide adequate assurance that requirements are being met. The 92-day Frequency for the COT and the 24 month Frequency for the TADOT ensure that the SR is performed at the start of each refueling and this Frequency is sufficient to provide a high degree of assurance that the valves will function as required throughout a refueling outage. Therefore, this change has no adverse impact on safety.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.6:

"Containment Purge System and Pressure Relief Line Isolation Instrumentation"

PART 5:

NUREG-1431
Annotated to show differences between NUREG-1431 and ITS

Status of NUREG 1431 Generic Changes for ITS 3.3.6

This ITS Specification is based on NUREG-1431 Specification No. **3.3.6**
as modified by the following Generic Changes:

OG No.	TSTF No.	Generic Change Description	NRC STATUS	IP3 STATUS	JD No.
BWROG-017	**051**	REVISE CONTAINMENT REQUIREMENTS DURING HANDLING IRRADIATED FUEL AND CORE ALTERATIONS (REQUIREMENTS LIMITED TO "RECENTLY" IRRADIATED FUEL)	NRC Review	Not Incorporated	**N/A**
WOG-066 R1	**161 R0**	SI REFERENCE APPLICABILITY	Approved by NRC	Does not apply to IP3	**N/A**
WOG-081		CHANGE FORMAT OF APPLICABILITY STATEMENT	Rejected by TSTF	Not Incorporated	**N/A**

3.3 INSTRUMENTATION

Pressure Relief Line

3.3.6 Containment Purge and Exhaust Isolation Instrumentation

<DOC A.3>

Pressure Relief

<T3.5-4, #4.a
T3.5-1, #1 and #2
(SEE ITS 3.3.2)>

LCO 3.3.6 The Containment Purge and Exhaust Isolation instrumentation for each Function in Table 3.3.6-1 shall be OPERABLE.

<T3.5-4, #4.a>
<3.8.A.8>
<DOC A.5>

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

ACTIONS

<DOC A.4>

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.	4 hours 7 days

<DOC M.1>
<T 3.5-4, #4.a>

DB.1

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. ---------NOTE--------- Only applicable in MODE 1, 2, 3, or 4. ---------- <T 3.5-4, #4.a> <DOC A.5> One or more isolation Functions with one or more ~~manual or~~ automatic actuation trains inoperable. <T 3.5-4, #4.a> <DOC A.6> **OR** Two ~~or more~~ 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 ~~and exhaust~~ isolation valves made inoperable by isolation instrumentation. pressure relief line	Immediately

DB.1

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. ---------NOTE--------- Only applicable during CORE ALTERATIONS or movement of irradiated fuel assemblies within containment. ---------- One or more Functions with one or more manual or automatic actuation trains inoperable. OR Two or more radiation monitoring channels inoperable. OR Required Action and associated Completion Time for Condition A not met.	C.1 Place and maintain containment purge and exhaust valves in closed position. OR C.2 Enter applicable Conditions and Required Actions of LCO 3.9.4, "Containment Penetrations," for containment purge and exhaust isolation valves made inoperable by isolation instrumentation.	Immediately system supply Immediately 3 system supply

<3.8.A.8>
<DOC A5>

<3.8.B>
(DOC A.6)

Containment purge system isolation

DB.1

Pressure Relief Line

SURVEILLANCE REQUIREMENTS

System

----------NOTE----------
Refer to Table 3.3.6-1 to determine which SRs apply for each Containment Purge and ~~Exhaust~~ Isolation Function.

	SURVEILLANCE		FREQUENCY
<T4.1-1, #15.b>	SR 3.3.6.1	Perform CHANNEL CHECK.	~~12~~ 24 hours (CLB.1)
<T4.1-1, #20.b>	SR 3.3.6.2	Perform ACTUATION LOGIC TEST.	31 days on a STAGGERED TEST BASIS
	~~SR 3.3.6.3~~	~~Perform MASTER RELAY TEST.~~	~~31 days on a STAGGERED TEST BASIS~~
<T4.1-1, #15.b> <3.8.A.8> <DOC L.1>	SR 3.3.6.~~4~~ 3	Perform COT.	92 days
	~~SR 3.3.6.5~~	~~Perform SLAVE RELAY TEST.~~	~~[92] days~~
<4.5.A.1.a> <4.5.A.2.a> <3.8.A.8> <DOC L.1>	SR 3.3.6.~~5~~ 4	----------NOTE---------- Verification of setpoint is not required. ---------- Perform TADOT.	~~[18]~~ 24 months
<T4.1-1, #15.b>	SR 3.3.6.~~7~~ 5	Perform CHANNEL CALIBRATION.	~~[18]~~ 24 months

Table 3.3.6-1 (page 1 of 1)
Containment Purge and Exhaust Isolation Instrumentation

FUNCTION	REQUIRED CHANNELS	SURVEILLANCE REQUIREMENTS	TRIP SETPOINT
1. ~~Manual Initiation~~	~~2~~	~~SR 3.3.6.6~~	~~NA~~
1 ~~2~~. Automatic Actuation Logic and Actuation Relays	2 trains	SR 3.3.6.2 ~~SR 3.3.6.5~~ ~~SR 3.3.6.5~~	NA
~~3~~. ~~Containment~~ Radiation Monitor		SR 3.3.6.4	(b)
2 ~~a~~. Gaseous (R-12)	~~[1]~~ 1	SR 3.3.6.1 SR 3.3.6.~~5~~ 4 SR 3.3.6.~~7~~ 5	≤ [2 x background]
3 ~~b~~. Particulate (R-11)	~~[1]~~ 1	SR 3.3.6.1 SR 3.3.6.~~5~~ 4 SR 3.3.6.~~7~~ 5	≤ ~~[2 x background]~~
~~c. Iodine~~	~~[1]~~	~~SR 3.3.6.1~~ ~~SR 3.3.6.6~~ ~~SR 3.3.6.7~~	~~≤ [2 x background]~~
~~d. Area Radiation~~	~~[1]~~	~~SR 3.3.6.1~~ ~~SR 3.3.6.6~~ ~~SR 3.3.6.7~~	~~≤ [2 x background]~~
4. ~~Containment Isolation - Phase A~~	Refer to LCO 3.3.2, "ESFAS Instrumentation," ~~Function 3.a~~, for all initiation functions and requirements.		

Functions 1 and 2

T 3.5-4, #4.a
T 3.5-1, #1,2

Insert: 3.3-54-01

Insert 3.3-54-02

NUREG-1431 Markup Inserts
ITS SECTION 3.3.6 - CONTAINMENT PURGE AND PRESSURE RELIEF ISOLATION INSTRUMENTATION

INSERT: 3.3-54-01

ESFAS Function 1, Safety Injection, and ESFAS Function 2, Containment Spray (a)

INSERT: 3.3-54-02

(a) Only required in MODES 1, 2, 3 and 4 as specified in LCO 3.3.2.

(b) As specified in the IP3 Offsite Dose Calculation Manual.

System

Pressure Relief Line

DB.1

CLB.1

B 3.3 INSTRUMENTATION

B 3.3.6 Containment Purge and Exhaust Isolation Instrumentation

BASES

pressure relief line

BACKGROUND

Containment purge and exhaust isolation instrumentation closes the containment isolation valves in the Mini Purge System and the Shutdown Purge System. This action isolates the containment atmosphere from the environment to minimize releases of radioactivity in the event of an accident. The Mini Purge System may be in use during reactor operation and the Shutdown Purge System will be in use with the reactor shutdown.

Pressure Relief

Containment

Containment Pressure Relief

may

Containment Purge

Insert: B3.3-150-01

Containment purge and exhaust isolation initiates on a automatic safety injection (SI) signal through the Containment Isolation—Phase A Function, or by manual actuation of Phase A Isolation. The Bases for LCO 3.3.2, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation," discuss these modes of initiation.

Four radiation monitoring channels are also provided as input to the containment purge and exhaust isolation. The four channels measure containment radiation at two locations. One channel is a containment area gamma monitor, and the other three measure radiation in a sample of the containment purge exhaust. The three purge exhaust radiation detectors are of three different types: gaseous, particulate, and iodine monitors. All four detectors will respond to most events that release radiation to containment. However, analyses have not been conducted to demonstrate that all credible events will be detected by more than one monitor. Therefore, for the purposes of this LCO the four channels are not considered redundant. Instead, they are treated as four one-out-of-one Functions. Since the purge exhaust monitors constitute a sampling system, various components such as sample line valves, sample line heaters, sample pumps, and filter motors are required to support monitor OPERABILITY.

Each of the purge systems has inner and outer containment isolation valves in its supply and exhaust ducts. A high radiation signal from any one of the four channels initiates containment purge isolation, which closes both inner and outer containment isolation valves in the Mini Purge System

(continued)

NUREG-1431 Markup Inserts
ITS SECTION 3.3.6 - CONTAINMENT PURGE AND
PRESSURE RELIEF ISOLATION INSTRUMENTATION

INSERT: B 3.3-150-01

The Containment Purge System consists of the 36-inch containment purge supply and exhaust penetrations. The containment purge supply and exhaust penetrations each include two butterfly valves for isolation. The containment purge exhaust penetration includes two butterfly valves for isolation and can be aligned to discharge to the atmosphere through the plant vent either directly or through the Containment Purge Filter System (i.e., a filter bank with roughing, HEPA and charcoal filters).

The Containment Purge System is isolated when in Modes 1, 2, 3 and 4 in accordance with requirements established in LCO 3.6.3, Containment Isolation Valves. In Modes 5 and 6, the Containment Purge System may be used for containment ventilation. When open, the Containment Purge System isolation valves are automatically closed when high radiation levels are detected by the Containment Air Particulate Monitor (R-11) or Containment Radioactive Gas Monitor (R-12).

The Containment Purge System isolation capability is not the primary method for ensuring that 10 CFR 100 limits are not exceeded during a fuel handling event (Ref. 1). As specified in LCO 3.9.3, Containment Penetrations, the Containment Purge System is aligned to discharge through the Containment Purge Filter System during CORE ALTERATIONS or movement of irradiated fuel until the reactor has been shutdown for at least 550 hours. Purge path filtration during the first 550 hours following reactor shutdown ensures that the does limit for a fuel handling accident of 75 rem to the thyroid (25 percent of the 10 CFR Part 100 limit of 300 rem) at the Exclusion Area Boundary (EAB) (i.e., site boundary) is not exceeded (Ref. 2).

INSERT: B 3.3-150-01 (Continued)

The Containment Pressure Relief Line (i.e., Containment Vent) consists of a single 10-inch containment vent line that is used to handle normal pressure changes in the Containment when in Modes 1, 2, 3 and 4. The Containment Pressure Relief Line is equipped with three quick-closing butterfly type isolation valves, one inside and two outside the containment which isolate automatically as part of Safety Injection ESFAS signal (LCO 3.3.2, Function 1) and Containment Spray ESFAS signal (LCO 3.3.2, Function 2). Automatic isolation of the Containment Pressure Relief Line is also initiated when high radiation levels are detected by the Containment Air Particulate Monitor (R-11) or Containment Radioactive Gas Monitor (R-12).

The Containment Pressure Relief Line is isolated during CORE ALTERATIONS or movement of irradiated fuel until the reactor has been shutdown during the first 550 hours following reactor shutdown as specified in LCO 3.9.3. Although the Containment Pressure Relief Line discharges to the atmosphere via the Containment Auxiliary Charcoal Filter System (i.e., a filter bank with roughing, HEPA and charcoal filters), the Containment Auxiliary Charcoal Filter System is not required to be tested in accordance with Specification 5.5.10, Ventilation Filter Test Program.

Both the Containment Purge supply and exhaust isolation valves (FCV-1170, FCV-1171, FCV-1172, and FCV-1173) and the containment pressure relief isolation valves (PCV-1190, PCV-1191, and PCV-1192) close when high radiation levels are detected by the Containment Air Particulate Monitor (R-11) or Containment Radioactive Gas Monitor (R-12). The Safety Injection ESFAS signal (LCO 3.3.2, Function 1) 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 specification requirements, containment purge and containment pressure relief are also isolated when high radiation levels are detected in the plant vent.

BASES

BACKGROUND (continued)

and the Shutdown Purge System. These systems are described in the Bases for LCO 3.6.3, "Containment Isolation Valves."

APPLICABLE SAFETY ANALYSES

Insert: B 3.3-151-01

The safety analyses assume that the containment remains intact with penetrations unnecessary for core cooling isolated early in the event, within approximately 60 seconds. The isolation of the purge valves has not been analyzed mechanistically in the dose calculations, although its rapid isolation is assumed. The containment purge and exhaust isolation radiation monitors act as backup to the SI signal to ensure closing of the purge and exhaust valves. They are also the primary means for automatically isolating containment in the event of a fuel handling accident during shutdown. Containment isolation in turn ensures meeting the containment leakage rate assumptions of the safety analyses, and ensures that the calculated accidental offsite radiological doses are below 10 CFR 100 (Ref. 1) limits.

pressure relief

The containment purge and exhaust isolation instrumentation satisfies Criterion 3 of the NRC Policy Statement. 10 CFR 50.36

LCO

Insert: B 3.3-151-02

The LCO requirements ensure that the instrumentation necessary to initiate Containment Purge and Exhaust Isolation listed in Table 3.3.6-1, is OPERABLE.

1. Manual Initiation

The LCO requires two channels OPERABLE. The operator can initiate Containment Purge Isolation at any time by using either of two switches in the control room. Either switch actuates both trains. This action will cause actuation of all components in the same manner as any of the automatic actuation signals.

The LCO for Manual Initiation ensures the proper amount of redundancy is maintained in the manual actuation circuitry to ensure the operator has manual initiation capability.

Each channel consists of one push button and the interconnecting wiring to the actuation logic cabinet.

(continued)

NUREG-1431 Markup Inserts
ITS SECTION 3.3.6 - CONTAINMENT PURGE AND
PRESSURE RELIEF ISOLATION INSTRUMENTATION

INSERT: B 3.3-151-01

In MODE 1, 2, 3 or 4, Containment Purge System automatic isolation capability is not required because the Containment Purge System is isolated in accordance with the requirements of LCO 3.6.3, Containment Isolation Valves.

During CORE ALTERATIONS or movement of irradiated fuel in the containment, Containment Purge System automatic isolation capability is required because it provides for automatic containment isolation in response to a fuel handling accident. As specified in LCO 3.9.3, Containment Penetrations, the Containment Purge System is aligned to discharge through the Containment Purge Filter System during CORE ALTERATIONS or movement of irradiated fuel until the reactor has been shutdown for at least 550 hours. Purge path filtration during the first 550 hours following reactor shutdown ensures that the dose limit for a fuel handling accident of 75 rem to the thyroid (25 percent of the 10 CFR Part 100 limit of 300 rem) at the EAB (i.e., site boundary) is not exceeded (Ref. 2). Although Containment Purge System isolation capability is not required to meet 10 CFR Part 100 limits during a fuel handling accident, this function provides a backup to the filtering function assumed in the analysis and is required to provide containment isolation following the event.

In MODE 1, 2, 3 or 4, Containment Pressure Relief Line automatic isolation capability is required as part of the containment isolation function initiated by the Engineered Safety Feature Actuation System (ESFAS) Instrumentation required by LCO 3.3.2. Containment Pressure Relief Line automatic isolation when high radiation levels are detected by the Containment Air Particulate Monitor (R-11) or Containment Radioactive Gas Monitor (R-12) provides a backup to the closure initiated by the ESFAS system.

During CORE ALTERATIONS or movement of irradiated fuel in the containment, Containment Pressure Relief Line automatic isolation capability is not required because the Containment Pressure Relief Line is isolated as specified in LCO 3.9.3. The Containment Pressure Relief Line is isolated because the fuel handling accident analysis (References 1 and 2) credits filtration and not automatic isolation to ensure 10 CFR 100 limits are met. The Containment Auxiliary Charcoal Filter System which filters the Containment Pressure Relief Line is not required to be tested in accordance with Specification 5.5.10, Ventilation Filter Test Program.

INSERT: B 3.3-151-02

This instrumentation is required to initiate automatic isolation of the Containment Purge System and the Containment Pressure Relief Line.

BASES

LCO (continued)

1 ~~2~~. 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.

Insert: B 33-152-01

~~Automatic Actuation Logic and Actuation Relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b, SI, and ESFAS Function 3.a, Containment Phase A Isolation. The applicable MODES and specified conditions for the containment purge isolation portion of these Functions are different and less restrictive than those for their Phase A isolation and SI roles.~~ If one or more of the SI 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 SI and ~~Phase A isolation~~ Functions need not be entered. The less restrictive Actions specified for inoperability of the Containment Purge Isolation Functions specify sufficient compensatory measures for this case.

Containment Spray and Pressure Relief Line

2 ~~3~~. Containment Radiation

The LCO specifies ~~four~~ two required channels of radiation monitors to ensure that the radiation monitoring instrumentation necessary to initiate Containment Purge Isolation remains OPERABLE.

Insert: B 3.3-152-02

~~For sampling systems,~~ 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 ~~4~~. ~~Containment Isolation—Phase A~~

Insert: B 3.3-152-03

Refer to LCO 3.3.2, ~~Function 3.a~~ Functions 1 and 2, for all initiating Functions and requirements.

(continued)

NUREG-1431 Markup Inserts
ITS SECTION 3.3.6 - CONTAINMENT PURGE AND
PRESSURE RELIEF ISOLATION INSTRUMENTATION

INSERT: B 3.3-152-01

Automatic Actuation Logic and Actuation Relays, is required to be Operable to support the Operability of all of the functions that isolate the containment purge system and pressure relief line (i.e., gaseous and particulate radiation monitors (R-11 and R-12) and ESFAS SI and containment spray initiation signals). Injection-Automatic Actuation Logic and Actuation Relays applies to those portions of the circuit that are: 1) common to more than one channel in one train of a single function (i.e., the automatic actuation logic); or, 2) the initiating relay contacts in one train responsible for actuating the equipment and which are common to both more than one channel of a single function and more than one function (i.e., the actuation relays). There are two trains of automatic actuation logic and actuation relays for the containment purge system and pressure relief line.

INSERT: B 3.3-152-02

The requirement for two channels is satisfied by the Containment Air Particulate Monitor (R-11) and the Containment Radioactive Gas Monitor (R-12). Allowable values and setpoints for these Functions are specified in the IP3 Offsite Dose Calculation Manual (Ref. 3).

INSERT: B 3.3-152-03

ESFAS Function 1, Safety Injection, and
ESFAS Function 2, Containment Spray

BASES (continued)

APPLICABILITY

Insert: B 3.3-153-01

~~The Manual Initiation, Automatic Actuation Logic and Actuation Relays, Containment Isolation—Phase A, and Containment Radiation Functions are required OPERABLE in MODES 1, 2, 3, and 4, and during CORE ALTERATIONS or movement of irradiated fuel assemblies within containment. Under these conditions, the potential exists for an accident that could release fission product radioactivity into containment. Therefore, the containment purge and exhaust isolation instrumentation must be OPERABLE in these MODES.~~

pressure relief line

While in MODES 5 and 6 without fuel handling in progress, the containment purge and exhaust isolation instrumentation need not be OPERABLE since 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. 10 CFR 100

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.

A.1

either the R-11 or the R-12

Condition A applies to the failure of ~~one containment purge~~ isolation radiation monitor channel. Since the ~~four~~ Two containment radiation monitors measure different parameters,

(continued)

NUREG-1431 Markup Inserts
ITS SECTION 3.3.6 - CONTAINMENT PURGE AND PRESSURE RELIEF ISOLATION INSTRUMENTATION

INSERT: B 3.3-153-01

In Modes 1, 2, 3 or 4, **Containment Purge System** automatic isolation capability is not required because the Containment Purge System is isolated in accordance with the requirements of LCO 3.6.3, Containment Penetrations.

During CORE ALTERATIONS or movement of irradiated fuel in the containment, **Containment Purge System** automatic isolation Function 1, Automatic Actuation Logic and Actuation Relays, and Function 2, Containment Radiation, are required to be OPERABLE to ensure Containment Purge System isolation in response to a fuel handling accident.

In Modes 1, 2, 3 or 4, **Containment Pressure Relief Line** automatic isolation Function 1, Automatic Actuation Logic and Actuation Relays, and Function 3, ESFAS Safety Injection and ESFAS Containment Spray, are required as part of the containment isolation function initiated by the Engineered Safety Feature Actuation System (ESFAS) Instrumentation required by LCO 3.3.2. Containment Pressure Relief Line automatic isolation Function 2, Containment Radiation, is required as a backup to the closure initiated by the ESFAS system.

During CORE ALTERATIONS or movement of irradiated fuel in the containment, **Containment Pressure Relief Line** automatic isolation capability is not required because the Containment Pressure Relief Line is isolated as specified in LCO 3.9.3.

BASES

ACTIONS

A.1 (continued)

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. The 4 hours allowed to restore the affected channel is justified by the low likelihood of events occurring during this interval, and recognition that one or more of the remaining channels will respond to most events.

Insert: B3.3-154-01

B.1

Pressure Relief line

Condition B applies to all Containment Purge and Exhaust Isolation Functions and addresses the train orientation of the Solid State Protection System (SSPS) and the master and slave relays for these 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.

both

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

Pressure Relief line

Condition C applies to all Containment Purge and Exhaust Isolation Functions and addresses the train orientation of the SSPS and the master and slave relays for these 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 and exhaust isolation

both

(continued)

NUREG-1431 Markup Inserts
ITS SECTION 3.3.6 - CONTAINMENT PURGE AND PRESSURE RELIEF ISOLATION INSTRUMENTATION

INSERT: B 3.3-154-01

However, 7 days is allowed to restore the affected channel because the containment radiation monitoring function is not the primary method or ensuring that 10 CFR limits are not exceed.

BASES

ACTIONS

C.1 and C.2 (continued)

valves in their closed position is met or the applicable Conditions of LCO 3.9.4, "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 CORE ALTERATIONS and during movement of 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 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 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

(continued)

NUREG-1431 Markup Inserts
ITS SECTION 3.3.6 - CONTAINMENT PURGE AND PRESSURE RELIEF ISOLATION INSTRUMENTATION

INSERT: B 3.3-155-01

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.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.6.1 (continued)

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. The train being tested is placed in the bypass condition, thus preventing inadvertent actuation. Through the semiautomatic tester, all possible logic combinations, with and without applicable permissives, are tested for each protection function. In addition, the master relay coil is pulse tested for continuity. This verifies that the logic modules are OPERABLE and there is an intact voltage signal path to the master relay coils. 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, verifying contact operation and a low voltage continuity check of the slave relay coil. 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.

SR 3.3.6.~~4~~3

radiation monitoring

A COT is performed every 92 days on each ~~required~~ channel to ensure the entire channel will perform the intended Function. The frequency is based on the staff recommendation for increasing the availability of radiation monitors according to NUREG-1366 (Ref. 2). This test verifies the capability of the instrumentation to provide the containment purge and exhaust system isolation. The

pressure relief line

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.6.~~4~~ 3 (continued)

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 SLAVE RELAY TEST. The SLAVE RELAY TEST is the energizing of the slave relays. Contact operation is verified in one of two ways. Actuation equipment that may be operated in the design mitigation mode is either allowed to function or is placed in a condition where the relay contact operation can be verified without operation of the equipment. Actuation equipment that may not be operated in the design mitigation mode is prevented from operation by the SLAVE RELAY TEST circuit. For this latter case, contact operation is verified by a continuity check of the circuit containing the slave relay. This test is performed every [92] days. The Frequency is acceptable based on instrument reliability and industry operating experience.

SR 3.3.6.~~6~~ 4

SR 3.3.6.6 is the performance of a TADOT. This test is a check of the Manual Actuation Functions and is performed every [18] months. Each Manual Actuation Function is tested up to, and including, the master relay coils. In some instances, the test includes actuation of the end device (i.e., pump starts, valve cycles, etc.).

24

that

The test also includes trip devices that provide actuation signals directly to the SSPS, 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.

Actuation Instrumentation

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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.~~7~~ 5

A CHANNEL CALIBRATION is performed every [18] 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.

Insert: B 3.3-158-01

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

REFERENCES

1. 10 CFR 100.~~11~~.
2. ~~NUREG-1366, [date]~~

Insert B 3.3-158-01

NUREG-1431 Markup Inserts
ITS SECTION 3.3.6 - CONTAINMENT PURGE AND PRESSURE RELIEF ISOLATION INSTRUMENTATION

INSERT: B 3.3-158-01

Allowable values and setpoints for these Functions are specified in the IP3 Offsite Dose Calculation Manual (Ref. 3).

INSERT: B 3.3-158-02

1. FSAR Chapter 14.
2. Safety Evaluation Report (SER) for IP3 Amendment 175.
3. IP3 Offsite Dose Calculation Manual.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.6:

"Containment Purge System and Pressure Relief Line Isolation Instrumentation"

PART 6:

Justification of Differences between

NUREG-1431 and IP3 ITS

JUSTIFICATION OF DIFFERENCES FROM NUREG-1431
ITS SECTION 3.3.6 - CONTAINMENT PURGE AND
PRESSURE RELIEF ISOLATION INSTRUMENTATION

RETENTION OF EXISTING REQUIREMENT (CURRENT LICENSING BASIS)

CLB.1 NUREG-1431, Rev 1, Section 3.3.6, was modified as needed to reflect the IP3 design and current licensing basis. A detailed description of the design, accident analysis assumptions, and Operability requirements are incorporated into the IP3 ITS Bases. These changes maintain the IP3 current licensing basis except as identified and justified in the CTS/ITS discussion of changes.

PLANT-SPECIFIC WORDING PREFERENCE OR MINOR EDITORIAL IMPROVEMENT

PA.1 Corrected typographical error or made a minor editorial improvement to improve clarity and ensure requirements are fully understood and consistently applied. There are no technical changes to requirements as specified in NUREG 1431, Rev. 1; therefore, this change is not a significant or generic deviation from NUREG 1431, Rev 1.

PLANT-SPECIFIC DIFFERENCE IN THE DESIGN OR DESIGN BASIS

DB.1 Design or implementation details are incorporated or revised as necessary to more precisely describe IP3 current design or practice. These changes are intended to describe the design, improve clarity, or ensure requirements are fully understood and consistently applied. Unless identified and described blow, these changes are self-explanatory. A detailed description of the design, accident analysis assumptions, and Operability requirements are incorporated into the IP3 ITS Bases. These changes maintain the IP3 current licensing basis except as identified and justified in the CTS/ITS discussion of changes.

DIFFERENCE BASED ON A GENERIC CHANGE TRAVELER FOR NUREG-1431

None

DIFFERENCE FOR ANY REASON OTHER THAN ABOVE

None

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.7:

"Control Room Emergency Ventilation (CRVS) Actuation Instrumentation"

PART 1:

Indian Point 3
Improved Technical Specifications and Bases

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, 4

ACTIONS

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

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more Functions with one channel or train inoperable.	A.1	Place CRVS in 10% incident mode.	7 days
B. One or more Functions with two channels or two trains inoperable.	B.1.1	Place CRVS in 10% incident mode.	72 hours
C. Required Action and associated Completion Time for Condition A or B not met.	C.1	Be in MODE 3.	6 hours
	AND		
	C.2	Be in MODE 5.	36 hours

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 COT.	92 days
SR 3.3.7.2	----------NOTE---------- Verification of setpoint is not required. ---------- Perform TADOT.	24 months

Table 3.3.7-1 (page 1 of 1)
CRVS Actuation Instrumentation

	FUNCTION	REQUIRED CHANNELS	SURVEILLANCE REQUIREMENTS	TRIP SETPOINT
1.	Manual Initiation	2	SR 3.3.7.2	NA
2.	Automatic Actuation Logic and Actuation Relays	2 trains	SR 3.3.7.1	NA
3.	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. During normal operation, the CRVS provides control room ventilation. Upon receipt of an actuation signal, the CRVS initiates filtered ventilation and pressurization of the control room. This system is described in the Bases for LCO 3.7.11 (Ventilation), "Control Room Ventilation System."

The control room operator can place the CRVS in the 10% incident mode described in the Bases for LCO 3.7.11, by manual mode selector switch in the control room. 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."

On a Safety Injection signal or high radiation in the Control Room (Radiation Monitor R-1), the CRVS will actuate to the <u>incident mode with outside air makeup</u> (i.e. 10% incident mode). This will cause one of the two filters booster fans to start, the locker room exhaust fan to stop, and CRVS dampers to open or close as necessary to filter incoming outside air and direct approximately 10% of the recirculated air through the filter unit. In the event that the first booster fan fails to start, the second booster fan will start after a predetermined time delay.

If for any reason it is required or desired to operate with 100% recirculated air (e.g., toxic gas condition is identified), the CRVS can be placed in the <u>incident mode with no outside air makeup</u> (i.e. 100% incident mode) by remote manually operated switches. The Firestat detector will also initiate 100% incident mode in the CRVS.

BASES

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 limit the supply of unfiltered outside air to the control room, initiate filtration, 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, SI signal actuation ensures initiation of the CRVS during a loss of coolant accident or steam generator tube rupture.

Radiation monitor R-1 is not required for the Operability of the Control Room Ventilation System because control room isolation is initiated by the safety injection signal in MODES 1, 2, 3 and 4 and control room isolation is not required for maintaining radiation exposure within General Design Criteria 19 limits following a fuel handling accident or gas-decay-tank rupture.

The CRVS does not actuate automatically in response to toxic gases. Separate chlorine, ammonia and oxygen probes are provided to detect the presence of these gases in the outside air intake. Additionally, monitors in the Control Room will detect low oxygen levels and high levels of chlorine and ammonia. The CRVS may be placed in the incident mode with no outside air makeup (i.e. 100% incident mode) to respond to these conditions. Instrumentation for toxic gas monitoring is governed by the IP3 Technical Requirements Manual (TRM) (Ref. 1).

Note that the original CRVS design was not required to meet single failure criteria and, although upgraded from the original design, CRVS does not satisfy all requirements in IEEE-279 for single failure tolerance.

The CRVS actuation instrumentation satisfies Criterion 3 of 10 CFR 50.36.

BASES

LCO

The LCO requirements ensure that instrumentation necessary to actuate the CRVS to the 10% incident mode is OPERABLE.

1. Manual Initiation

The LCO requires two channels OPERABLE because the CRVS mode selector switch has two channels (i.e., one channel for each train). The operator can initiate the CRVS at any time by using the CRVS mode selector switch in the control room. This action will cause actuation of all components in the same manner as the automatic actuation signal.

Each channel includes the common CRVS mode selector switch and the interconnecting wiring to the actuation logic cabinet.

2. Automatic Actuation Logic and Actuation Relays

The LCO requires two trains of Actuation Logic and Relays OPERABLE to ensure that no single random failure can prevent automatic actuation resulting from an SI signal.

Automatic Actuation Logic and Actuation relays are required to be OPERABLE to support the Operability of the function that starts CRVS (i.e., and ESFAS SI initiation signals). The term automatic actuation logic and actuation relays applies to those portions of the circuit that are: 1) common to more than one channel in one train of a single function (i.e., the automatic actuation logic); or, 2) the initiating relay contacts in one train responsible for actuating the equipment and which are common to more than one channel of a single function and more than one function (i.e., the actuation relays). There are two trains of automatic actuation logic and actuation relays for the containment purge system and pressure relief line.

If the SI functions becomes inoperable in such a manner that only the CRVS function is affected, the Conditions applicable to their SI function need not be entered. The less restrictive Actions specified for inoperability of the CRVS Functions specify sufficient compensatory measures for this case.

BASES

LCO (continued)

3. Safety Injection

Refer to LCO 3.3.2, Function 1, for all initiating Functions and requirements.

APPLICABILITY

The CRVS Functions must be OPERABLE in MODES 1, 2, 3 and 4 to ensure a habitable environment for the control room operators.

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 to the manual channels and the actuation logic train Function of the CRVS.

If one channel or train is inoperable in one or more Functions, 7 days are permitted to restore it to OPERABLE status. The 7 day Completion Time is the same as is allowed if one train of the mechanical portion of the system is inoperable. The basis for this Completion Time is the same as provided in LCO 3.7.11. If the channel/train cannot be restored to OPERABLE status, CRVS must be placed in the emergency radiation protection mode of operation (i.e., the 10% incident mode). This starts both trains of CRVS because a single switch controls both trains. This accomplishes the actuation instrumentation Function and places the unit in a conservative mode of operation.

BASES

ACTIONS (continued)

B.1

Condition B applies to the failure of two CRVS actuation trains, or two manual channels. The first Required Action is to place CRVS in the 10% incident mode of operation within 72 hours. This starts both trains of CRVS because a single switch controls both trains. This accomplishes the actuation instrumentation Function that may have been lost and places the unit in a conservative mode of operation. This ensures appropriate limits are placed upon train inoperability as discussed in the Bases for LCO 3.7.11.

C.1 and C.2

Condition C applies when the Required Action and associated Completion Time for Condition A or B 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.

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.

SR 3.3.7.1

A COT is performed once every 92 days on each required channel to ensure the entire channel will perform the intended function. This test verifies the capability of the instrumentation to provide the CRVS actuation. The Frequency is based on the known

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.7.1 (continued)

reliability of the system and has been shown to be acceptable through operating experience.

SR 3.3.7.2

SR 3.3.7.2 is the performance of a TADOT. This test is a check of the Manual Actuation Functions and is performed every 24 months. Each Manual Actuation Function is tested up to, and including, the end device (i.e., fan starts, damper cycles, etc.).

The Frequency is based on the known reliability of the Function and has been shown to be acceptable through operating experience. The SR is modified by a Note that excludes verification of setpoints during the TADOT. The Functions tested have no setpoints associated with them.

REFERENCES

1. IP3 Technical Requirements Manual.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.7:
"Control Room Emergency Ventilation (CRVS) Actuation Instrumentation"

PART 2:

CURRENT TECHNICAL SPECIFICATION PAGES

Annotated to show differences between CTS and ITS

CTS pages and associated TSCRs annotated for this ITS Specification :

CTS Page No.	Effective Amendment	Annotated Amendment	TSCR No.	TSCR Description	ITS Status of TSCR
3.3-11	154	154	No TSCRs	No TSCRs for this Page	N/A
3.3-20	145	145	No TSCRs	No TSCRs for this Page	N/A
4.1-1	97	97	No TSCRs	No TSCRs for this Page	N/A
T 4.1-1(3)	168 TSCR 98-043	168 TSCR 98-043	IPN 98-043	Instrument Channel Surveillance Intervals Extended to 24 Months	Incorporated

SEE CTS MASTER MARKUP

G. Containment Hydrogen Monitoring Systems

1. One hydrogen monitor including a flow path and associated containment fan cocler unit shall be OPERABLE whenever the reactor T_{avg} exceeds 350°F.

   a. The requirements of 3.3.G.1 can be modified to allow both containment hydrogen monitoring systems to be inoperable for a period not to exceed 7 days.

H. Control Room Ventilation System — Actuation instrumentation — A.3

1. The control room ventilation system shall be operable at all times when containment integrity is required as per specification 3.6 — Mode 1, 2, 3 and 4 — A.4

2. The requirements of 3.3.H.1 may be modified as follows:

   a. The control room ventilation system may be inoperable for a period not to exceed seventy-two hours. At the end of this period, if the mal-condition in the control room ventilation system has not been corrected, the reactor shall be placed in the hot shutdown condition utilizing normal operating procedures. If after an additional 48 hours the mal-condition still exists, the reactor shall be placed in the cold shutdown condition utilizing normal operating procedures. — M.1

Add Req. Actions A.1, B.1 and C.1 and C.2

SEE CTS MASTER MARKUP

3. Two independent toxic gas monitoring systems, with separate channels for detecting chlorine, ammonia, and oxygen shall be operable in accordance with 3.3.H.1 except as specified below. The alarms for ammonia and chlorine shall be adjusted to actuate at ≤35 ppm and ≤3 ppm, respectively.

   a. With any channel for a monitored toxic gas inoperable, restore the inoperable channel to operable status within 7 days.

   b. If 3.a above cannot be satisfied within the specified time, then within the next 8 hours initiate and maintain operation in the control room of alternate monitoring capability for the inoperable channel.

   c. With both channels for a monitored gas inoperable, within 8 hours initiate and maintain operation in the control room of an alternate monitoring system capable of detecting the gas monitored by the inoperable channel.

Amendment No. ~~34~~, ~~80~~, ~~98~~, ~~101~~, ~~108~~, ~~113~~, 154

4.1

The containment hydrogen monitoring system consists of two safety related hydrogen concentration measurement cabinets with sample lines which pass through the containment penetrations to each containment fan cooler unit plenum. Two of the five sampling lines (from containment fan cooler units nos. 32 and 35) are routed to a common source line and then to a hydrogen monitor. The other three sample lines (from containment fan cooler units nos. 31, 33 and 34) are likewise headered and routed to the other hydrogen monitor. Each monitor has a separate return line. The design hydrogen concentration for operating the recombiner is established at 3% by volume. Conservative calculations indicate that the hydrogen content within the containment will not reach 3% by volume until 10 days after a loss-of-coolant accident.[10] There is, therefore, no need for immediate operation of the recombiner following an accident.

Auxiliary Component Cooling Pumps are provided to deliver cooling water for the two Recirculation Pumps located inside the containment. Each recirculation pump is fed by two Auxiliary Component Cooling Pumps. A single Auxiliary Component Cooling Pump is capable of supplying the necessary cooling water required for a recirculation pump during the recirculation phase following a loss-of-coolant accident.

The control room ventilation is designed to filter the control room atmosphere for intake air and/or for recirculation during control room isolation conditions. The control room system is designed to automatically start upon control room isolation and to maintain the control room pressure to the design positive pressure so that all leakage should be out leakage.

Radiation monitor R-1 is not part of the Control Room Ventilation System. NRC letter dated January 27, 1982 concluded that, at IP3, "radiation monitors for makeup air are not required." NYPA has also demonstrated (calculation dated May 29, 1992) that Central Control Room (CCR) isolation is not required for maintaining radiation exposure within General Design Criteria 19 limits following a fuel handling accident or gas-decay-tank rupture. For a loss of coolant accident, CCR isolation is initiated by the safety injection signal.

The control room is equipped with two independent toxic gas monitoring systems. One system in the control room consists of a channel for oxygen (with two oxygen detectors) and a channel each for ammonia and chlorine. The second system in the control room ventilation intake consists of one channel each for oxygen, ammonia and chlorine. Oxygen detectors are used to indirectly monitor changes in carbon dioxide levels.

4 SURVEILLANCE REQUIREMENTS

4.1 OPERATIONAL SAFETY REVIEW

A.2

Applicability

Applies to items directly related to safety limits and limiting conditions for operation. Performance of any surveillance test outlined in these specifications is not required if the plant condition is the same as the condition into which the plant would be placed by an unsatisfactory result of that test. Failure to perform a surveillance requirement within the allowed surveillance interval (including extensions specified in definition 1.12), shall constitute noncompliance with the operability requirements of the limiting conditions for operation (LCOs). The time limits for associated action requirements are applicable at the time it is identified that a surveillance requirement has not been performed. Action requirements may be delayed for up to 24 hours to permit completion of the missed surveillance when the allowable outage time limits of the action requirements are less than 24 hours (i.e. for LCOs of less than 24 hours, a 24 hour delay period is permitted before entering the LCO; for LCOs greater than 24 hours, no delay period is permitted).

Objective

To specify the minimum frequency and type of surveillance to be applied to plant equipment and conditions.

Specification

A. Calibration, testing, and checking of analog channel and testing of logic channel shall be performed as specified in Table 4.1-1.

B. Sampling and equipment tests shall be conducted as specified in Table 4.1-2 and 4.1-3, respectively.

A.1

A.1

Basis

A surveillance test is intended to identify conditions in a plant that would lead to a degradation of reactor safety. Should a test reveal such a condition, then the Technical Specifications require that, either immediately or after a specified period of time, the plant be placed in a condition which mitigates or eliminates the consequences of additional related casualties or accidents. If the plant is already in a

Add SR 3.3.7.1
SR 3.3.7.2 (M.2)

TABLE 4.1-1 (Sheet 3 of 6)

SEE CTS MASTER MARKUP

Channel Description	Check	Calibrate	Test	Remarks
e. Main Steam Lines Process Radiation Monitors (R-62A, R-62B, R-62C, and R-62D)	D	24M	Q	
f. Gross Failed Fuel Detectors (R-63A and R-63B)	D	24M	Q	
16. Containment Water Level Monitoring System:				
a. Containment Sump	N.A.	24M	N.A.	Narrow Range, Analog
b. Recirculation Sump	N.A.	24M	N.A.	Narrow Range, Analog
c. Containment Water Level	N.A.	24M	N.A.	Wide Range
17. Accumulator Level and Pressure	S	24M	N.A.	
18. Steam Line Pressure	S	24M	Q	
19. Turbine First Stage Pressure	S	24M	Q	
20a. Reactor Trip Relay Logic	N.A.	N.A.	TM	
20b. ESF Actuation Relay Logic	N.A.	N.A.	TM	
21. Turbine Trip Low Auto Stop Oil Pressure	N.A.	24M	N.A.	
22. DELETED	DELETED	DELETED	DELETED	
23. Temperature Sensor in Auxiliary Boiler Feedwater Pump Building	N.A.	N.A.	18M	
24. Temperature Sensors in Primary Auxiliary Building				
a. Piping Penetration Area	N.A.	N.A.	24M	
b. Mini-Containment Area	N.A.	N.A.	24M	
c. Steam Generator Blowdown Heat Exchanger Room	N.A.	N.A.	24M	

SEE CTS MASTER MARKUP

ITS 3.3.7

Amendment No. 38, 65, 74, 93, 100, 107, 123, 127, 133, 137, 139, 150, 164, 167, 168, TSCR 98-043

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.7:
"Control Room Emergency Ventilation (CRVS) Actuation Instrumentation"

PART 3:

DISCUSSION OF CHANGES

Differences between CTS and ITS

DISCUSSION OF CHANGES
ITS SECTION ITS SECTION 3.3.7 - CONTROL ROOM VENTILATION SYSTEM (CREVS) ACTUATION INSTRUMENTATION

ADMINISTRATIVE

A.1 In the conversion of the Indian Point Unit 3 Current Technical Specifications (CTS) to the plant specific Improved Technical Specifications (ITS) certain wording preferences or conventions are adopted which do not result in technical changes (either actual or interpretational). Additionally, editorial changes, reformatting, and revised numbering are adopted to make ITS consistent with the conventions in NUREG-1431, Standard Technical Specifications, Westinghouse Plants, Rev. 1, i.e., the improved Standard Technical Specifications.

The CTS Bases are deleted and replaced with comprehensive ITS Bases designed to support interpretation and implementation of the associated Technical Specifications. The Bases explain, clarify, and document the reasons (i.e., bases) for the associated Technical Specifications, and reflect the IP3 plant specific design, analyses, and licensing basis. In accordance with 10 CFR 50.36(a), the ITS Bases are included with the proposed ITS conversion application; however, deletion of the CTS Bases and the adoption of the ITS Bases is an administrative change with no impact on safety.

A.2 CTS Limiting Conditions for Operation (LCOs) and Surveillance Requirements (SRs) include statements of the objective and the applicability. The CTS statements of objective and applicability are deleted because these statements do not establish any requirements and do not provide any guidance for the application of CTS requirements. Therefore, deletion of these statements has no significant adverse impact on safety.

A.3 CTS 3.3.H.1 requires that the control room ventilation system be operable in Mode 1, 2, 3 and 4. ITS LCO 3.3.7, Control Room Ventilation System (CRVS) Actuation Instrumentation, is added to establish explicit requirements for the associated actuation instrumentation. CRVS design provides CRVS actuation to the incident mode with outside air makeup (i.e. 10% incident mode) based on manual actuation of the CRVS mode

selector switch, a safety injection signal or high radiation in the Control Room (Radiation Monitor R-1). However, actuation on Radiation Monitor R-1 is not included in Technical Specifications because isolation of the control room is not required for maintaining radiation exposure within General Design Criteria 19 limits following a fuel handling accident or gas decay tank rupture (See Amendment No. 137 to Facility Operating License DPR-64 for IP3). Therefore, CRVS actuation on an SI signal provides the required actuation signal.

Adding explicit requirements for CRVS actuation instrumentation is an administrative change with no adverse impact of safety because it is an explicit statement of a reasonable interpretation of the existing requirement.

A.4 CTS 3.3.H.1 requires that the control room ventilation system be operable at all times when containment integrity is required (i.e., Mode 1, 2, 3 and 4). ITS LCO 3.7.11, Control Room Ventilation System (CRVS), and ITS 3.3.7, CRVS Actuation Instrumentation, are applicable during Modes 1, 2, 3, and 4 (i.e., above cold shutdown). This is an administrative change with no impact on safety because there is no change to the existing requirements.

This Applicability is acceptable based on a determination that isolation of the control room is not required for maintaining radiation exposure within General Design Criteria 19 limits following a fuel handling accident or gas decay tank rupture. Therefore, the control room ventilation system is not required to be operable in Modes 5 and 6, and during movement of irradiated fuel assemblies and core alterations. (See Amendment No. 137 to Facility Operating License DPR-64 for the Indian Point Nuclear Generating Unit No. 3.)

MORE RESTRICTIVE

M.1 CTS 3.3.H.1 requires that the control room ventilation system be operable in Mode 1, 2, 3 and 4. ITS LCO 3.3.7, CRVS Actuation Instrumentation, is added to establish explicit requirements for the

associated actuation instrumentation (i.e., manual actuation, automatic actuation logic and actuation relays, and SI actuation). In conjunction with this change, Conditions and Required Actions are added to address when one or more required channels are inoperable.

Required Action A.1 specifies that 7 days are permitted to restore Operability if one channel or train is inoperable. The basis for this Completion Time is the same as provided in LCO 3.7.11 for an inoperable CRVS train. If the channel/train cannot be restored to OPERABLE status within the completion Time, CRVS must be placed in the 10% incident mode because this action accomplishes the actuation instrumentation function and places the unit in a conservative mode of operation. Note that both trains of CRVS are placed in the 10% incident mode because both trains are controlled by one switch.

Required Actions B.1.1 and B.1.2 specify that if two channels or trains of the same initiation function are inoperable (i.e., loss of an initiation function), then CRVS must be placed in the 10% incident mode immediately because this action accomplishes the actuation instrumentation function and places the unit in a conservative mode of operation. Note that both trains of CRVS are placed in the 10% incident mode because both trains are controlled by one switch. The 72 hour Completion Time for placing CRVS are placed in the 10% incident mode is consistent with the 72 hour AOT in ITS 3.7.11 when both trains of CRVS are inoperable.

These more restrictive change are acceptable because they do not introduce any operation that is un-analyzed while establishing an explicit and conservative requirements when one or more CRVS actuation functions is not Operable. Therefore, this change has no significant adverse impact on safety.

M.2 CTS 3.3.H.1 requires that the control room ventilation system be operable in Mode 1, 2, 3 and 4. ITS LCO 3.3.7, CRVS Actuation Instrumentation, is added to establish explicit requirements for the associated actuation instrumentation (i.e., manual actuation, Automatic Actuation Logic and Actuation Relays, and SI actuation). However, there

is no explicit requirement for periodic verification that channel logic and channel end devices (e.g., fan start capability, damper cycling, etc) are Operable. ITS SR 3.3.7.1 is added to require a Channel Operational Test of the CRVS automatic actuation logic and actuation relays. ITS SR 3.3.7.1 is added to require a Trip Actuating Device Operational Test (TADOT) of the CRVS end devices using the manual actuation channel. These changes are needed because they ensure that CRVS actuation instrumentation and associated end devices function as required. These more restrictive changes are acceptable because they does not introduce any operation that is un-analyzed while establishing an explicit requirement for periodic verification that channel end devices (e.g., fan start capability, damper cycling, etc) are Operable. Therefore, this change has no significant adverse impact on safety.

LESS RESTRICTIVE

None

REMOVED DETAIL

None

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.7:

"Control Room Emergency Ventilation (CRVS) Actuation Instrumentation"

PART 4:

No Significant Hazards Considerations for Changes between CTS and ITS that are Less Restrictive

No Significant Hazard Considerations for Changes that are Administrative, More Restrictive, and Removed Details are the same for all Packages. A Copy is included at the end of the Package.

NO SIGNIFICANT HAZARDS EVALUATION
ITS SECTION ITS SECTION 3.3.7 - CONTROL ROOM VENTILATION SYSTEM (CREVS) ACTUATION INSTRUMENTATION

LESS RESTRICTIVE
("L.1" Labeled Comments/Discussions)

There are no less restrictive changes for the adoption of this ITS.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.7:

"Control Room Emergency Ventilation (CRVS) Actuation Instrumentation"

PART 5:

NUREG-1431
Annotated to show differences between NUREG-1431 and ITS

Status of NUREG 1431 Generic Changes for ITS 3.3.7

This ITS Specification is based on NUREG-1431 Specification No. 3.3.7
as modified by the following Generic Changes:

OG No.	TSTF No.	Generic Change Description	NRC STATUS	IP3 STATUS	JD No.
BWROG-017	051	REVISE CONTAINMENT REQUIREMENTS DURING HANDLING IRRADIATED FUEL AND CORE ALTERATIONS (REQUIREMENTS LIMITED TO "RECENTLY" IRRADIATED FUEL)	NRC Review	Not Incorporated	N/A
WOG-066 R1	161 R0	SI REFERENCE APPLICABILITY	Approved by NRC	Does not apply to IP3	N/A

3.3 INSTRUMENTATION

<CTS> **3.3.7 Control Room ~~Emergency Filtration~~ Ventilation System (CREFS) (CRVS) Actuation Instrumentation**

<3.3.H> <DOC A.3> LCO 3.3.7 The ~~CREFS~~ CRVS actuation instrumentation for each Function in Table 3.3.7-1 shall be OPERABLE.

<3.3.H.1> <DOC A.4> APPLICABILITY: MODES 1, 2, 3, and 4, ~~[5, and 6,]~~ ~~During movement of irradiated fuel assemblies,~~ ~~[During CORE ALTERATIONS],~~

ACTIONS

NOTE
Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
<DOC H.1> A. One or more Functions with one channel or train inoperable.	A.1 ~~NOTE Place in toxic gas protection mode if automatic transfer to toxic gas protection mode is inoperable.~~ Place ~~one CREFS train~~ CRVS in ~~emergency [radiation protection]~~ 10% incident mode.	7 days

DB.1

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One or more Functions with two channels or two trains inoperable.	~~NOTE~~ ~~Place in the toxic gas protection mode if automatic transfer to toxic gas protection mode is inoperable.~~	
	B.1 Place one CREFS train in ~~emergency [radiation protection]~~ mode.	CRVS ~~Immediately~~ 72 hours CLB
	AND	
	B.1.2 Enter applicable Conditions and Required Actions for one CREFS train made inoperable by inoperable CREFS actuation instrumentation.	Immediately CLB.1 DB.1
	OR	
	B.2 Place both trains in emergency [radiation protection] mode.	Immediately
C. Required Action and associated Completion Time for Condition A or B not met in ~~MODE 1, 2, 3, or 4~~.	C.1 Be in MODE 3.	6 hours
	AND	
	C.2 Be in MODE 5.	36 hours

(DOC M.1)
(3.3.H.2.a)
10% incident
(DOC M.1)

~~(continued)~~

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required Action and associated Completion Time for Condition A or B not met during movement of irradiated fuel assemblies [or during CORE ALTERATIONS].	D.1 Suspend CORE ALTERATIONS. AND	Immediately
	D.[2] Suspend movement of irradiated fuel assemblies.	Immediately
E. Required Action and associated Completion Time for Condition A or B not met in MODE 5 or 6.	E.1 Initiate action to restore one CREFS train to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

----------NOTE----------
Refer to Table 3.3.7-1 to determine which SRs apply for each CREFS Actuation Function.

SURVEILLANCE		FREQUENCY
SR 3.3.7.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.7.2	Perform COT.	92 days

<DOC M.2>

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.7.3	Perform ACTUATION LOGIC TEST.	31 days on a STAGGERED TEST BASIS
SR 3.3.7.4	Perform MASTER RELAY TEST.	31 days on a STAGGERED TEST BASIS
SR 3.3.7.5	Perform SLAVE RELAY TEST.	[92] days
<DOC M.2> SR 3.3.7.~~6~~ 2	----------NOTE---------- Verification of setpoint is not required. ---------- Perform TADOT.	~~[18]~~ 24 months
SR ~~3.3.7.7~~	~~Perform CHANNEL CALIBRATION.~~	~~[18]~~ months

Table 3.3.7-1 (page 1 of 1)
CREFS Actuation Instrumentation

FUNCTION	REQUIRED CHANNELS	SURVEILLANCE REQUIREMENTS	TRIP SETPOINT
1. Manual Initiation	~~2 trains~~ One	SR 3.3.7.6 2	NA
2. Automatic Actuation Logic and Actuation Relays	2 trains	SR 3.3.7.3 1 ~~SR 3.3.7.4~~ ~~SR 3.3.7.5~~	NA
~~3. Control Room Radiation~~			
~~a. Control Room Atmosphere~~	~~[2]~~	~~SR 3.3.7.1~~ ~~SR 3.3.7.2~~ ~~SR 3.3.7.7~~	~~≤ [2] mR/hr~~
~~b. Control Room Air Intakes~~	~~[2]~~	~~SR 3.3.7.1~~ ~~SR 3.3.7.2~~ ~~SR 3.3.7.7~~	~~≤ [2] mR/hr~~
3 ~~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 ~~Emergency Filtration~~ Ventilation System ~~(CREFS)~~ CRVS Actuation Instrumentation

BASES

BACKGROUND

The ~~CREFS~~ CRVS provides an enclosed control room environment from which the unit can be operated following an uncontrolled release of radioactivity. During normal operation, the ~~Auxiliary Building Ventilation System~~ CRVS provides control room ventilation. Upon receipt of an actuation signal, the ~~CREFS~~ CRVS initiates filtered ventilation and pressurization of the control room. This system is described in the Bases for LCO 3.7.~~10~~ 11, "Control Room ~~Emergency Filtration~~ Ventilation System."

~~The actuation instrumentation consists of redundant radiation monitors in the air intakes and control room area. A high radiation signal from any of these detectors will initiate both trains of the CREFS. The control room operator can also initiate CREFS trains by manual switches in the control room. The CREFS 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."~~

place the CRVS in the 10% incident mode described in the Bases for LCO 3.7.11

mode selector switch

Insert: B3.3-159-01

APPLICABLE SAFETY ANALYSES

The control room must be kept habitable for the operators stationed there during accident recovery and post accident operations.

The ~~CREFS~~ CRVS acts to ~~terminate~~ limit the supply of unfiltered outside air to the control room, initiate filtration, 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 monitor actuation of the CREFS is a backup for the~~ SI signal actuation. ~~This~~ ensures initiation of the ~~CREFS~~ CRVS during a loss of coolant accident or steam generator tube rupture.

Insert B3.3-159-02

~~The radiation monitor actuation of the CREFS in MODES 5 and 6, during movement of irradiated fuel assemblies [, and~~

(continued)

NUREG-1431 Markup Inserts
ITS SECTION ITS SECTION 3.3.7 - CONTROL ROOM VENTILATION SYSTEM (CREVS) ACTUATION INSTRUMENTATION

INSERT: B 3.3-159-01

On a Safety Injection signal or high radiation in the Control Room (Radiation Monitor R-1), the CRVS will actuate to the incident mode with outside air makeup (i.e. 10% incident mode). This will cause one of the two filters booster fans to start, the locker room exhaust fan to stop, and CRVS dampers to open or close as necessary to filter incoming outside air and direct approximately 10% of the recirculated air through the filter unit. In the event that the first booster fan fails to start, the second booster fan will start after a predetermined time delay.

If for any reason it is required or desired to operate with 100% recirculated air (e.g., toxic gas condition is identified), the CRVS can be placed in the incident mode with no outside air makeup (i.e. 100% incident mode) by remote manually operated switches. The Firestat detector will also initiate 100% incident mode in the CRVS.

INSERT: B 3.3-159-02

Radiation monitor R-1 is not required for the Operability of the Control Room Ventilation System because control room isolation is initiated by the safety injection signal in MODES 1, 2, 3 and 4 and control room isolation is not required for maintaining radiation exposure within General Design Criteria 19 limits following a fuel handling accident or gas-decay-tank rupture.

The CRVS does not actuate automatically in response to toxic gases. Separate chlorine, ammonia and oxygen probes are provided to detect the presence of these gases in the outside air intake. Additionally, monitors in the Control Room will detect low oxygen levels and high levels of chlorine and ammonia. The CRVS may be placed in the incident mode with no outside air makeup (i.e. 100% incident mode) to respond to these conditions. Instrumentation for toxic gas monitoring is governed by the IP3 Technical Requirements Manual (TRM) (Ref. 1).

Note that the original CRVS design was not required to meet single failure criteria and, although upgraded from the original design, CRVS does not satisfy all requirements in IEEE-279 for single failure tolerance.

BASES

APPLICABLE SAFETY ANALYSES (continued)

~~CORE ALTERATIONS], is the primary means to ensure control room habitability in the event of a fuel handling or waste gas decay tank rupture accident.~~

The CREFS actuation instrumentation satisfies Criterion 3 of ~~the NRC Policy Statement~~. 10 CFR 50.36

LCO

The LCO requirements ensure that instrumentation necessary to ~~initiate the CREFS~~ actuate the CRVS to the 10% mode is OPERABLE.

1. Manual Initiation

The LCO requires two channels OPERABLE because the CRVS mode selector switch has two channels (i.e., one channel for each train). The operator can initiate the CREFS at any time by using ~~either of two switches~~ the CRVS mode selector switch in the control room. This action will cause actuation of all components in the same manner as ~~any of~~ the automatic actuation signal~~s~~.

~~The LCO for Manual Initiation ensures the proper amount of redundancy is maintained in the manual actuation circuitry to ensure the operator has manual initiation capability.~~

Each channel ~~consists of one push button~~ includes the common CRVS mode selector switch and the interconnecting wiring to the actuation logic cabinet.

2. Automatic Actuation Logic and Actuation Relays

The LCO requires two trains of Actuation Logic and Relays OPERABLE to ensure that no single random failure can prevent automatic actuation resulting from an SI signal.

Insert B3.3-160-01

~~Automatic Actuation Logic and Actuation Relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b., SI, in LCO 3.3.2. The applicable MODES and specified conditions for the CREFS portion of these functions are different and less restrictive than those specified for their SI roles.~~ If one or more of the SI functions becomes inoperable in such a manner that only the CREFS function is affected, the Conditions applicable to their SI function need not be entered. The less

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(continued)

NUREG-1431 Markup Inserts
ITS SECTION ITS SECTION 3.3.7 - CONTROL ROOM VENTILATION SYSTEM (CREVS) ACTUATION INSTRUMENTATION

INSERT: B 3.3-160-01

Automatic Actuation Logic and Actuation Relays are required to be Operable to support the Operability of the function that starts CRVS (i.e., an ESFAS SI initiation signals). The term automatic actuation logic and actuation relays applies to those portions of the circuit that are: 1) common to more than one channel in one train of a single function (i.e., the automatic actuation logic); or, 2) the initiating relay contacts in one train responsible for actuating the equipment and which are common to both more than one channel of a single function and more than one function (i.e., the actuation relays). There are two trains of automatic actuation logic and actuation relays for the containment purge system and pressure relief line.

BASES

LCO

2. Automatic Actuation Logic and Actuation Relays (continued)

restrictive Actions specified for inoperability of the CRVS ~~CREFS~~ Functions specify sufficient compensatory measures for this case.

3. Control Room Radiation

The LCO specifies two required Control Room Atmosphere Radiation Monitors and two required Control Room Air Intake Radiation Monitors to ensure that the radiation monitoring instrumentation necessary to initiate the CREFS remains OPERABLE.

For sampling systems, channel OPERABILITY involves more than OPERABILITY of 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 ~~4~~. Safety Injection

Refer to LCO 3.3.2, Function 1, for all initiating Functions and requirements.

APPLICABILITY

The CREFS Functions must be OPERABLE in MODES 1, 2, 3, 4, [and during CORE ALTERATIONS] and movement of irradiated fuel assemblies. The Functions must also be OPERABLE in MODES [5 and 6] when required for a waste gas decay tank rupture accident, to ensure a habitable environment for the control room operators.

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 the unit specific calibration procedures. Typically, the drift is found to be small and results in a delay of actuation rather

(continued)

BASES

ACTIONS (continued)

~~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 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 to the manual channels and the actuation logic train Function of the CREFS, ~~the radiation monitor channel Functions, and the manual channel Functions~~.

If one channel or train is inoperable, ~~or one radiation monitor channel is inoperable~~ in one or more Functions, 7 days are permitted to restore it to OPERABLE status. The 7 day Completion Time is the same as is allowed if one train of the mechanical portion of the system is inoperable. The basis for this Completion Time is the same as provided in LCO 3.7.~~10~~ 11. If the channel/train cannot be restored to OPERABLE status, ~~one~~ CREFS ~~train~~ must be placed in the emergency radiation protection mode of operation. This accomplishes the actuation instrumentation Function and places the unit in a conservative mode of operation.

(i.e., the 10% recirc mode). This starts both trains of CRVS because a single switch controls both trains.

~~The Required Action for Condition A is modified by a Note that requires placing one CREFS train in the toxic gas protection mode instead of the [radiation protection] mode of operation if the automatic transfer to toxic gas protection mode is inoperable. This ensures the CREFS train is placed in the most conservative mode of operation relative to the OPERABILITY of the associated actuation instrumentation.~~

(continued)

BASES

ACTIONS (continued)

B.1, B.1.2, and B.2

Condition B applies to the failure of two CREFS actuation trains, two radiation monitor channels, or two manual channels. The first Required Action is to place one CREFS train in the emergency [radiation protection] mode of operation immediately. This accomplishes the actuation instrumentation Function that may have been lost and places the unit in a conservative mode of operation. The applicable Conditions and Required Actions of LCO 3.7.10 must also be entered for the CREFS train made inoperable by the inoperable actuation instrumentation. This ensures appropriate limits are placed upon train inoperability as discussed in the Bases for LCO 3.7.10.

CRVS

10% incident

within 72 hours

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Alternatively, both trains may be placed in the emergency [radiation protection] mode. This ensures the CREFS function is performed even in the presence of a single failure.

The Required Action for Condition B is modified by a Note that requires placing one CREFS train in the toxic gas protection mode instead of the [radiation protection] mode of operation if the automatic transfer to toxic gas protection mode is inoperable. This ensures the CREFS train is placed in the most conservative mode of operation relative to the OPERABILITY of the associated actuation instrumentation.

C.1 and C.2

Condition C applies when the Required Action and associated Completion Time for Condition A or B 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.

(continued)

BASES

ACTIONS (continued)

D.1 and D.2

Condition D applies when the Required Action and associated Completion Time for Condition A or B have not been met [during CORE ALTERATIONS or] when irradiated fuel assemblies are being moved. Movement of irradiated fuel assemblies [and CORE ALTERATIONS] must be suspended immediately to reduce the risk of accidents that would require CREFS actuation.

E.1

Condition E applies when the Required Action and associated Completion Time for Condition A or B have not been met in MODE 5 or 6. Actions must be initiated to restore the inoperable train(s) to OPERABLE status immediately to ensure adequate isolation capability in the event of a waste gas decay tank rupture.

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 CREFS CRVS Actuation Functions.

SR 3.3.7.1

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 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,

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.7.1 (continued)

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 3.3.7.~~2~~1

A COT is performed once every 92 days on each required channel to ensure the entire channel will perform the intended function. This test verifies the capability of the instrumentation to provide the CREFS actuation. The setpoints shall be left consistent with the unit specific calibration procedure tolerance. The Frequency is based on the known reliability of the monitoring equipment and has been shown to be acceptable through operating experience.

CRVS

system

SR 3.3.7.3

SR 3.3.7.3 is the performance of an ACTUATION LOGIC TEST. The train being tested is placed in the bypass condition, thus preventing inadvertent actuation. Through the semiautomatic tester, all possible logic combinations, with and without applicable permissives, are tested for each protection function. In addition, the master relay coil is pulse tested for continuity. This verifies that the logic modules are OPERABLE and there is an intact voltage signal path to the master relay coils. This test is performed every 31 days on a STAGGERED TEST BASIS. The Frequency is justified in WCAP-10271-P-A, Supplement 2, Rev. 1 (Ref. 1).

SR 3.3.7.4

SR 3.3.7.4 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.7.4 (continued)

check of the slave relay coil. 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 Frequency is acceptable based on instrument reliability and industry operating experience.

SR 3.3.7.5

SR 3.3.7.5 is the performance of a SLAVE RELAY TEST. The SLAVE RELAY TEST is the energizing of the slave relays. Contact operation is verified in one of two ways. Actuation equipment that may be operated in the design mitigation MODE is either allowed to function or is placed in a condition where the relay contact operation can be verified without operation of the equipment. Actuation equipment that may not be operated in the design mitigation MODE is prevented from operation by the SLAVE RELAY TEST circuit. For this latter case, contact operation is verified by a continuity check of the circuit containing the slave relay. This test is performed every [92] days. The Frequency is acceptable based on instrument reliability and industry operating experience.

SR 3.3.7.6 2

SR 3.3.7.6 is the performance of a TADOT. This test is a check of the Manual Actuation Functions and is performed every [18] months. Each Manual Actuation Function is tested up to, and including, the master relay coils. In some instances, the test includes actuation of the end device (i.e., pump starts, valve cycles, etc.). damper

24

fan

The test also includes trip devices that provide actuation signals directly to the Solid State Protection System, bypassing the analog process control equipment. 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. The SR is modified by a Note that excludes verification of setpoints during the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.7.~~6~~ 2 (continued)

TADOT. The Functions tested have no setpoints associated with them.

SR 3.3.7.7

~~A CHANNEL CALIBRATION is performed every [18] months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy.~~

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

REFERENCES

~~None.~~

1. IP3 Technical Requirement Manual

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.7:

"Control Room Emergency Ventilation (CRVS) Actuation Instrumentation"

PART 6:

Justification of Differences between

NUREG-1431 and IP3 ITS

JUSTIFICATION OF DIFFERENCES FROM NUREG-1431
ITS SECTION ITS SECTION 3.3.7 - CONTROL ROOM VENTILATION SYSTEM
(CREVS) ACTUATION INSTRUMENTATION

RETENTION OF EXISTING REQUIREMENT (CURRENT LICENSING BASIS)

CLB.1 NUREG-1431, Rev 1, Section 3.3.8, was modified as needed to reflect the IP3 design and current licensing basis. A detailed description of the design, accident analysis assumptions, and Operability requirements are incorporated into the IP3 ITS Bases. These changes maintain the IP3 current licensing basis except as identified and justified in the CTS/ITS discussion of changes.

PLANT-SPECIFIC WORDING PREFERENCE OR MINOR EDITORIAL IMPROVEMENT

PA.1 Corrected typographical error or made a minor editorial improvement to improve clarity and ensure requirements are fully understood and consistently applied. There are no technical changes to requirements as specified in NUREG 1431, Rev. 1; therefore, this change is not a significant or generic deviation from NUREG 1431, Rev 1.

PLANT-SPECIFIC DIFFERENCE IN THE DESIGN OR DESIGN BASIS

DB.1 Design or implementation details are incorporated or revised as necessary to more precisely describe IP3 current design or practice. These changes are intended to describe the design, improve clarity, or ensure requirements are fully understood and consistently applied. Unless identified and described blow, these changes are self-explanatory. A detailed description of the design, accident analysis assumptions, and Operability requirements are incorporated into the IP3 ITS Bases. These changes maintain the IP3 current licensing basis except as identified and justified in the CTS/ITS discussion of changes.

DIFFERENCE BASED ON A GENERIC CHANGE TRAVELER FOR NUREG-1431

None

DIFFERENCE FOR ANY REASON OTHER THAN ABOVE

None

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.8:

"Fuel Storage Building Emergency Ventilation System (FSBEVS) Instrumentation"

PART 1:

Indian Point 3
Improved Technical Specifications and Bases

3.3 INSTRUMENTATION

3.3.8 Fuel Storage Building Emergency Ventilation System (FSBEVS) Actuation Instrumentation

LCO 3.3.8 FSBEVS actuation instrumentation shall be OPERABLE.

APPLICABILITY: During movement of irradiated fuel in the fuel storage building.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. FSBEVS actuation instrumentation inoperable.	A.1 Place FSBEVS in operation.	Immediately
	OR	
	A.2 Suspend movement of irradiated fuel in the fuel storage building.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.8.1	Perform CHANNEL CHECK.	24 hours
SR 3.3.8.2	Perform COT.	92 days
SR 3.3.8.3	Perform CHANNEL CALIBRATION.	24 months

B 3.3 INSTRUMENTATION

B 3.3.8 Fuel Storage Building Emergency Ventilation System (FSBEVS) Actuation Instrumentation

BASES

BACKGROUND

The FSBEVS ensures that radioactive materials in the fuel building atmosphere following a fuel handling accident are filtered and adsorbed prior to exhausting to the environment. The system is described in the Bases for LCO 3.7.13, Fuel Storage Building Emergency Ventilation System (FSBEVS). The system initiates filtered ventilation of the fuel building automatically following receipt of a high radiation signal from fuel storage building area radiation monitor, R-5.

High radiation levels detected by the fuel storage building area radiation monitor, R-5, initiates fuel storage building isolation and starts the FSBEVS. These actions function to prevent exfiltration of contaminated air by initiating filtered ventilation, which imposes a negative pressure on the fuel storage building. Following an Area Radiation Monitor (R-5) signal or manual actuation to the emergency mode of operation, the FSBEVS ventilation supply fans stop automatically and the associated ventilation supply dampers close automatically. The charcoal filter face dampers (inlet and outlet dampers) open automatically, if not already open. Additionally, the rolling door closes, if open, and the inflatable seals on the man doors and truck door are actuated. The FSB exhaust fan continues to operate.

APPLICABLE SAFETY ANALYSES

The FSBEVS ensures that radioactive materials in the fuel building atmosphere following a fuel handling accident are filtered and adsorbed prior to being exhausted to the environment when the FSBEVS is aligned and operates as described in the Bases for LCO 3.7.13, Fuel Storage Building Emergency Ventilation System (FSBEVS). This action reduces the radioactive content in the fuel building exhaust following a LOCA or fuel handling

BASES

APPLICABLE SAFETY ANALYSES (continued)

accident so that offsite doses remain within the limits specified in 10 CFR 100 (Ref. 1).

The FSBEVS actuation instrumentation satisfies Criterion 3 of 10 CFR 50.36.

LCO

The LCO requirements ensure that instrumentation necessary for manual and automatic actuation of the FSBEVS is OPERABLE.

Manual and automatic FSBEVS initiation capability is OPERABLE when the Fuel Storage Building Area Radiation Monitor (R-5) signal or manual actuation to the emergency mode of operation will cause the realignment of the FSBEVS to the accident mode of operation as described in the Bases for LCO 3.7.13, Fuel Storage Building Emergency Ventilation System (FSBEVS).

The setpoint for Fuel Storage Building Area Radiation Monitor (R-5) is established in accordance with the Offsite Dose Calculation Manual (ODCM) (Ref. 2).

APPLICABILITY

The manual FSBEVS initiation must be OPERABLE when moving irradiated fuel assemblies in the fuel storage building, to ensure the FSBEVS operates to remove fission products associated with leakage after a fuel handling accident.

High radiation initiation of the FSBEVS must be OPERABLE in any MODE during movement of irradiated fuel assemblies in the fuel storage building to ensure automatic initiation of the FSBEVS when the potential for a fuel handling accident exists.

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 Reference 2. Typically, the drift is found to be small and results in a delay of actuation

BASES

ACTIONS (continued)

rather than a total loss of function. This determination is generally made during the performance of a COT, when the instrumentation is set up for adjustment to bring it within specification. If the Trip Setpoint is less conservative than the tolerance specified by Reference 2, the channel must be declared inoperable immediately and the appropriate Condition entered.

A.1 and A.2

This condition applies when the manual or automatic FSBEVS initiation capability is inoperable. The Required Action is to immediately place the system in operation as described in the Bases for LCO 3.7.13, FSBEVS. This accomplishes the actuation instrumentation function that may have been lost and places the unit in a accident mode of operation. Alternatively, movement of irradiated fuel assemblies in the fuel building must be suspended immediately to eliminate the potential for events that could require FSBEVS actuation. The Completion Time of immediately requires that the Required Action be pursued without delay and in a controlled manner.

SURVEILLANCE REQUIREMENTS

SR 3.3.8.1

Performance of the CHANNEL CHECK once every 24 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

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.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.8.1 (continued)

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

SR 3.3.8.2

A COT is performed for both the manual and automatic function once every 92 days to ensure the entire channel will perform the intended function. This test verifies the capability of the instrumentation to provide the FSBEVS actuation. The setpoints shall be left consistent with requirements of Reference 2. The Frequency of 92 days is based on the known reliability of the monitoring equipment and has been shown to be acceptable through operating experience. This test is typically performed in conjunction with SR 3.7.13.4 which verifies OPERABILITY of the activated devices.

SR 3.3.8.3

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 is based on operating experience and is consistent with the refueling cycle.

REFERENCES

1. 10 CFR 100.11.

2. IP3 Offsite Dose Calculation Manual.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.8:

"Fuel Storage Building Emergency Ventilation System (FSBEVS) Instrumentation"

PART 2:

CURRENT TECHNICAL SPECIFICATION PAGES

Annotated to show differences between CTS and ITS

CTS pages and associated TSCRs annotated for this ITS Specification :

CTS Page No.	Effective Amendment	Annotated Amendment	TSCR No.	TSCR Description	ITS Status of TSCR
3.8-2	175	175	No TSCRs	No TSCRs for this Page	N/A
3.8-3	114	114	No TSCRs	No TSCRs for this Page	N/A
3.8-4	173	173	No TSCRs	No TSCRs for this Page	N/A
3.8-5	173	173	No TSCRs	No TSCRs for this Page	N/A
3.8-6	175	175	No TSCRs	No TSCRs for this Page	N/A
T 4.1-1(2)	169	169	No TSCRs	No TSCRs for this Page	N/A

8. The containment vent and purge system, including the radiation monitors which initiate isolation, shall be tested and verified to be operable within 100 hours prior to refueling operations.

9. No movement of irradiated fuel in the reactor shall be made until the reactor has been subcritical for at least 145 hours. In addition, movement of fuel in the reactor before the reactor has been subcritical for equal to or greater than 421* hours will necessitate operation of the Containment Building Vent and Purge System through the HEPA filters and charcoal absorbers. For this case operability of the Containment Building Vent and Purge System shall be established in accordance with Section 4.13 of the Technical Specifications. In the event that more than 76 assemblies are to be discharged from the reactor, those assemblies in excess of 76 shall not be discharged earlier than 267 hours after shutdown.

SEE CTS MASTER MARKUP

10. Whenever movement of irradiated fuel is being made, the minimum water level in the area of movement shall be maintained 23 feet over the top of the reactor pressure vessel flange.

11. Hoists or cranes utilized in handling irradiated fuel shall be dead- load tested before movement begins. The load assumed by the hoists or cranes for this test must be equal to or greater than the maximum load to be assumed by the hoists or cranes during the refueling operation. A thorough visual inspection of the hoists or cranes shall be made after the deadload test and prior to fuel handling. A test of interlocks and overload cutoff devices on the manipulator shall also be performed.

LCO 3.8.3 and applicability

12. The fuel storage building emergency ventilation actuation instrs system shall be operable whenever irradiated fuel is being handled within the fuel storage building. The emergency ventilation system may be inoperable when irradiated fuel is in the fuel storage building, provided irradiated fuel is not being handled and neither the spent fuel cask nor the cask crane are moved over the spent fuel pit during the period of inoperability. A.3

13. To ensure redundant decay heat removal capability, at least two of the following requirements shall be met:

SEE CTS MASTER MARKUP

* Movement of irradiated VANTAGE + fuel assemblies before the reactor has been subcritical for ≥550 hours requires operation of the Containment Building Vent and Purge System through the HEPA filters and charcoal adsorbers.

Add Req. Action A.1.2 — L.1

SEE CTS MASTER MARKUP

a. No. 31 residual heat removal pump and heat exchanger, together with their associated piping and valves are operable.

b. No. 32 residual heat removal pump and heat exchanger, together with their associated piping and valves are operable.

c. The water level in the refueling cavity above the top of the reactor vessel flange is equal to or greater than 23 feet.

Req. Act A.1.2

B. If any of the specified limiting conditions for refueling are not met, refueling shall cease until the specified limits are met, and no operations which may increase the reactivity of the core shall be made. A.4

SEE CTS MASTER MARKUP

C. During fuel handling and storage operations, the following conditions shall be met:

1. Radiation levels in the spent fuel storage area shall be monitored continuously whenever there is irradiated fuel stored therein. If the monitor is inoperable, a portable monitor may be used.

2. The spent fuel cask shall not be moved over any region of the spent fuel pit which contains irradiated fuel. Additionally, if the spent fuel pit contains irradiated fuel, no loads in excess of 2,000 pounds shall be moved over any region of the spent fuel pit.

3. During periods of spent fuel cask or fuel storage building cask crane movement over the spent fuel pit, or during periods of spent fuel movement in the spent fuel pit when the pit contains irradiated fuel, the pit shall be filled with borated water at a concentration of >1000 ppm.

4. Whenever movement of irradiated fuel in the spent fuel pit is being made, the minimum water level in the area of movement shall be maintained 23 feet over the top of irradiated fuel assemblies seated in the storage rack.

SEE CTS MASTER MARKUP

5. Hoists or cranes utilized in handling irradiated fuel shall be deadload tested before fuel movement begins. The load assumed by the hoists or cranes for this test must be equal to or greater than the maximum load to be assumed by the hoists or cranes during the fuel handling operation. A thorough visual inspection of the hoists or cranes shall be made after the deadload test prior to fuel handling.

LCO 3.3.8. Applicability

6. The fuel storage building emergency ventilation system (actuation units) shall be operable whenever irradiated fuel is being handled within the fuel storage building. The emergency ventilation system may be inoperable when irradiated fuel is in the fuel storage building, provided irradiated fuel is not being handled and neither the spent fuel cask nor the cask crane are moved over the spent fuel pit during the periods of inoperability. A.3

SEE CTS MASTER MARKUP

7. The spent fuel storage racks consist of two regions, as shown on Figure 3.8-3: Region 1 (Columns SS-ZZ, Rows 35-64) and Region 2 (Columns A-RR, Rows 1-34). Fuel storage is restricted in each region as follows:

   a. As specified in Figure 3.8-2, fuel assemblies to be stored in Region 2 shall have a minimum burnup exposure as a function of initial enrichment.

   b. As specified in Figure 3.8-1, fuel assemblies to be stored in Region 1 consist of 3 types (Type A, B, C), depending on their initial enrichment and current burnup. Restrictions on location of fuel in Region 1 are as follows:

      1. Type A assemblies may be stored anywhere in Region 1.

      2. A Type B assembly may be stored anywhere in Region 1, provided it is not face-adjacent to a Type C assembly.

      3. Type C assemblies may not be stored in Row 64 or Column ZZ of Region 1. A Type C assembly may be stored in any other Region 1 location provided that all surrounding (face-adjacent) locations are occupied by Type A assemblies, non-fuel components or empty.

D. When any fuel assemblies are in the reactor vessel and the reactor vessel head bolts are less than fully tensioned, the boron concentration of all filled portions of the Reactor Coolant System and the refueling canal shall be maintained uniform and sufficient to ensure that the more restrictive of the following reactivity conditions is met; either:

Amendment No. 30, 34, 69, 70, 86, 90, 114, 173

SEE CTS MASTER MARK UP

a. A shutdown margin greater than or equal to 5% ΔK/K

or

b. A boron concentration of greater than or equal to 1900 ppm.

The required boron concentration will be verified by chemical analysis daily. With the requirements of the above specification not satisfied, immediately suspend all operations involving core alterations or positive reactivity changes and initiate boration to return to the more restrictive of the limits above.

Basis

The equipment and general procedures to be utilized during refueling, fuel handling, and storage are discussed in the FSAR. Detailed instructions, the above specified precautions, and the design of the fuel handling equipment incorporating built-in interlocks and safety features, provide assurance that no incident could occur during the refueling, fuel handling, reactor maintenance or storage operations that would result in a hazard to public health and safety.[1] Whenever changes are not being made in core geometry, one flux monitor is sufficient. This permits maintenance of the instrumentation. Continuous monitoring of radiation levels and neutron flux provides immediate indication of an unsafe condition. The residual heat removal pump is used to maintain a uniform boron concentration.

The shutdown margin indicated will keep the core subcritical. During refueling the reactor refueling cavity is filled with approximately 342,000 gallons of water from the refueling water storage tank with a boron concentration of 2400-2600 ppm. Periodic checks of refueling water boron concentration and residual heat removal pump operation insure the proper shutdown margin. The requirement for direct communications allows the control room operator to inform the manipulator operator of any impending unsafe condition detected from the main control board indicators during fuel movement. A.

The minimum boron concentration of this water is the more restrictive of either 1900 ppm or else sufficient to maintain the reactor subcritical by at least 5% ΔK/K in the cold shutdown condition with all rods inserted. These limitations are consistent with the initial conditions assumed for the boron dilution incident in the safety analyses.

In addition to the above safeguards, interlocks are utilized during refueling to ensure safe handling. An excess weight interlock is provided on the lifting hoist to prevent movement of more than one fuel assembly at a time. The spent fuel transfer mechanism can accommodate only one fuel assembly at a time.

The 145-hour decay time following the subcritical condition and the 23 feet of water above the top of the reactor pressure vessel flange bounds the assumptions used in the dose calculation for the fuel-handling accident. The 145-hour decay time is based on limiting calculated worst-case spent fuel pool temperature rise to 150°F with up to 76 assemblies discharged from the reactor.

A.1

The waiting time of 267 hours required following plant shutdown before unloading more than 76 assemblies from the reactor assures that the maximum pool water temperature will be within design objectives as stated in the FSAR. The calculations confirming this are based on an inlet river temperature of 95°F, consistent with the FSAR assumptions[2].

The requirement for the fuel storage building emergency ventilation system to be operable is established in accordance with standard testing requirements to assure that the system will function to reduce the offsite dose to within acceptable limits in the event of a fuel-handling accident. The fuel storage building emergency ventilation system must be operable whenever irradiated fuel is being moved. However, if the irradiated fuel has had a continuous 45 day decay period, the fuel storage building emergency ventilation system is not technically necessary, even though the system is required to be operable during all fuel handling operations. Fuel Storage Building isolation is actuated upon receipt of a signal from the area high activity alarm or by manual operation. The emergency ventilation bypass assembly is manually isolated, using manual isolation devices, prior to movement of any irradiated fuel. This ensures that all air flow is directed through the emergency ventilation HEPA filters and charcoal adsorbers. The ventilation system is tested prior to all fuel handling activities to ensure the proper operation of the filtration system.

When fuel in the reactor is moved before the reactor has been subcritical for at least 421 hours (See footnote on page 3.8-2), the limitations on the containment vent and purge system ensure that all radioactive material released from an irradiated fuel assembly will be filtered through the HEPA filters and charcoal adsorbers prior to discharge to the atmosphere.

The limit to have at least two means of decay heat removal operable ensures that a single failure of the operating RHR System will not result in a total loss of decay heat removal capability. With the reactor head removed and 23 feet of water above the vessel flange, a large heat sink is available for core cooling. Thus, in the event of a single component failure, adequate time is provided to initiate diverse methods to cool the core.

The minimum spent fuel pit boron concentration and the restriction of the movement of the spent fuel cask over irradiated fuel were specified in order to minimize the consequences of an unlikely sideways cask drop.

TABLE 4.1-1 (Sheet 2 of 6)

	Channel Description	Check	Calibrate	Test	Remarks
SEE CTS MASTER MARKUP	8. 6.9 KV Voltage	N.A.	18M	Q	Reactor protection circuits only
	6.9 KV Frequency	N.A.	24M	Q	Reactor protection circuits only
	9. Analog Rod Position	S	24M	M	
	10. Steam Generator Level	S	24M	Q	
	11. Residual Heat Removal Pump Flow	N.A.	24M	N.A.	
	12. Boric Acid Tank Level	S	24M	N.A.	Bubbler tube rodded during calibration
	13. Refueling Water Storage Tank Level				
	a. Transmitter	W	18M	N.A.	Low level alarm
	b. Indicating Switch	W	6M	N.A.	Low level alarm
	14a. Containment Pressure - narrow range	S	24M	Q	High and High-High
	14b. Containment Pressure - wide range	M	18M	N.A.	
SR 3.3.8.1 3.3.8.2 3.3.8.3 3.3.8.4	15. Process and Area Radiation Monitoring:	SR 3.3.8.1	SR 3.3.8.4	SR 3.3.8.2	See ITS 3.7.11
	a. Fuel Storage Building Area Radiation Monitor (R-5)	D	24M	Q	
SEE CTS MASTER MARKUP	b. Vapor Containment Process Radiation Monitors (R-11 and R-12)	D	24M	Q	
	c. Vapor Containment High Radiation Monitors (R-25 and R-26)	D	24M	Q	
	d. Wide Range Plant Vent Gas Process Radiation Monitor (R-27)	D	24M	Q	

Amendment No. 8, 38, 63, 68, 74, 93, 107, 123, 137, 140, 144, 148, 150, 154, 169

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.8:

"Fuel Storage Building Emergency Ventilation System (FSBEVS) Instrumentation"

PART 3:

DISCUSSION OF CHANGES

Differences between CTS and ITS

DISCUSSION OF CHANGES
ITS SECTION 3.3.8 - FUEL STORAGE BUILDING EMERGENCY VENTILATION SYSTEM (FSBEVS) INSTRUMENTATION

ADMINISTRATIVE

A.1 In the conversion of the Indian Point Unit 3 Current Technical Specifications (CTS) to the plant specific Improved Technical Specifications (ITS) certain wording preferences or conventions are adopted which do not result in technical changes (either actual or interpretational). Additionally, editorial changes, reformatting, and revised numbering are adopted to make ITS consistent with the conventions in NUREG-1431, Standard Technical Specifications, Westinghouse Plants, Rev. 1, i.e., the improved Standard Technical Specifications.

The CTS Bases are deleted and replaced with comprehensive ITS Bases designed to support interpretation and implementation of the associated Technical Specifications. The Bases explain, clarify, and document the reasons (i.e., bases) for the associated Technical Specifications, and reflect the IP3 plant specific design, analyses, and licensing basis. In accordance with 10 CFR 50.36(a), the ITS Bases are included with the proposed ITS conversion application; however, deletion of the CTS Bases and the adoption of the ITS Bases is an administrative change with no impact on safety.

A.2 CTS Limiting Conditions for Operation (LCOs) and Surveillance Requirements (SRs) include statements of the objective and the applicability. The CTS statements of objective and applicability are deleted because these statements do not establish any requirements and do not provide any guidance for the application of CTS requirements. Therefore, deletion of these statements has no significant adverse impact on safety.

A.3 CTS 3.8.A.12 and 3.8.C.6 require that the fuel storage building emergency ventilation system be Operable whenever irradiated fuel is being handled within the fuel storage building. Although there is no explicit requirement for the Operability of the associated actuation instrumentation, CTS Table 4.4-1, Item 15.a, requires periodic verification of the fuel storage building area radiation monitor, R-5,

which provides automatic actuation of the fuel storage building emergency ventilation system. LCO 3.7.13, Fuel Storage Building Emergency Ventilation System (FSBEVS), maintains the requirement for FSBEVS Operability and LCO 3.3.8, Fuel Storage Building Emergency Ventilation System (FSBEVS) Actuation Instrumentation, is added to establish an explicit requirement for the Operability of the manual and automatic actuation instrumentation for the FSBEVS. This is an administrative change with no adverse impact of safety because it is an explicit statement of a reasonable interpretation of the existing requirement.

A.4 CTS 3.8.A establishes requirements for fuel handling operations both in the containment and in the fuel storage building. CTS 3.8.B specifies that if any of these requirements are not met, then refueling shall cease until the specified limits are met, and no operations which may increase the reactivity of the core shall be made. ITS LCO 3.3.8, Required Action A.1.2, which applies to the FSBEVS only, maintains the requirement to stop handling of irradiated fuel in the FSB. However, the requirement to halt operations which may increase the reactivity of the core is deleted. This change is acceptable because FSBEVS Operability is not assumed in the analysis of a fuel handling accident in containment. This is an administrative change with no adverse impact of safety because it is an explicit statement of a reasonable interpretation of the existing requirement.

MORE RESTRICTIVE

None

LESS RESTRICTIVE

L.1 CTS 3.8.B requires that refueling (i.e., fuel handling in the FSB) cease if the fuel storage building emergency ventilation system (and implicitly the actuation instrumentation) is inoperable. ITS 3.3.8, Required Action A.1.2 maintains this requirement; however, ITS 3.3.8,

DISCUSSION OF CHANGES
ITS SECTION 3.3.8 - FUEL STORAGE BUILDING EMERGENCY VENTILATION SYSTEM (FSBEVS) INSTRUMENTATION

Required Action A.1.1, adds the option of placing the FSBEVS in operation immediately upon discovery that either the manual initiation function or automatic initiation function is inoperable. This option will allow fuel handling in the FSB to continue. This change is acceptable because this action places the FSBEVS in accident mode of operation (as described in the Bases of LCO 3.7.13). Therefore, this action accomplishes LCO safety function and ensures the FSBEVS is in a conservative mode of operation if a fuel handling accident occurs. Therefore, this change does not have a significant adverse impact on safety.

REMOVED DETAIL

None

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.8:

"Fuel Storage Building Emergency Ventilation System (FSBEVS) Instrumentation"

PART 4:

No Significant Hazards Considerations for Changes between CTS and ITS that are Less Restrictive

No Significant Hazard Considerations for Changes that are Administrative, More Restrictive, and Removed Details are the same for all Packages. A Copy is included at the end of the Package.

NO SIGNIFICANT HAZARDS EVALUATION
ITS SECTION 3.3.8 - FUEL BUILDING AIR CLEANUP SYSTEM (FBACS)
ACTUATION INSTRUMENTATION

LESS RESTRICTIVE
("L.1" Labeled Comments/Discussions)

New York Power Authority has evaluated the proposed Technical Specification change identified as "Less Restrictive" in accordance with the criteria set forth in 10 CFR 50.92, and has determined that the proposed change does not involve a significant hazards consideration. The bases for the determination that the proposed change does not involve a significant hazards consideration are discussed below.

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

   This change allows refueling to continue upon discovery that the fuel storage building emergency ventilation system actuation instrumentation manual initiation function or automatic initiation function is inoperable, provided the fuel storage building emergency ventilation system is placed in operation to provide filtered ventilation immediately. CTS 3.8.B requires that refueling cease if the fuel storage building emergency ventilation system (and implicitly the actuation instrumentation) is inoperable.

   This change will not result in a significant increase in the probability of an accident previously evaluated because the fuel storage building emergency ventilation system is a system to mitigate the consequences of a fuel handling accident, and placing it operation to provide filtered ventilation would not increase the probability that a fuel handling accident would occur.

   This change will not result in a significant increase in the consequences of an accident previously evaluated because the actuation instrumentation function is accomplished by placing the fuel storage building emergency ventilation system in operation to provide filtered ventilation, and the unit is in a conservative mode of operation should a fuel handling accident occur.

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

   The proposed change will not involve any physical changes to systems, structures, or components, or involve a change in normal plant operation. Therefore, it will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   This change does not involve a significant reduction in a margin of safety because the fuel storage building emergency ventilation system is placed in operation to provide filtered ventilation, thereby accomplishing its safety function, and the unit is in a conservative mode of operation should a fuel handling accident occur.

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PART 5:

NUREG-1431
Annotated to show differences between NUREG-1431 and ITS

Status of NUREG 1431 Generic Changes for ITS 3.3.8

This ITS Specification is based on NUREG-1431 Specification No. **3.3.8**
as modified by the following Generic Changes:

OG No.	TSTF No.	Generic Change Description	NRC STATUS	IP3 STATUS	JD No.
BWROG-008 R1	**036 R1**	ADDITION OF LCO 3.0.3 N/A TO SHUTDOWN ELECTRICAL POWER SPECIFICATIONS	Rejected by TSTF	See Rev 2	**N/A**
BWROG-008 R3	**036 R3**	ADDITION OF LCO 3.0.3 N/A TO SHUTDOWN ELECTRICAL POWER SPECIFICATIONS	NRC Rejects: TSTF to Revise	Not Incorporated	**N/A**
BWROG-017	**051**	REVISE CONTAINMENT REQUIREMENTS DURING HANDLING IRRADIATED FUEL AND CORE ALTERATIONS (REQUIREMENTS LIMITED TO "RECENTLY" IRRADIATED FUEL)	NRC Review	Not Incorporated	**N/A**

Insert: 3.3-60-01

3.3 INSTRUMENTATION

3.3.8 ~~Fuel Building Air Cleanup System (FBACS)~~ Actuation Instrumentation

LCO 3.3.8 ~~The FBACS actuation instrumentation for each Function in Table 3.3.8-1 shall be OPERABLE.~~ CLB.1

Insert: 3.3-60-02

APPLICABILITY: According to Table 3.3.8-1.

Insert: 3.3-60-03

ACTIONS

~~NOTE~~
~~Separate Condition entry is allowed for each Function.~~ DB.1

CONDITION	REQUIRED ACTION	COMPLETION TIME
~~A. One or more Functions with one channel or train inoperable.~~	~~A.1 Place one FBACS train in operation.~~	~~7 days~~
A. ~~B.~~ One or more Functions with two channels or two trains inoperable.	A. ~~B.~~1.1 Place ~~one FBACS train~~ FSBEVS in operation.	Immediately CLB.1 DB.1
	~~AND~~	
	~~B.1.2 Enter applicable Conditions and Required Actions of LCO 3.7.13, "Fuel Building Air Cleanup System (FBACS)," for one train made inoperable by inoperable actuation instrumentation.~~	Immediately
	~~OR~~	
		(continued)

Insert: 3.3-60-04

Insert 3.3-60-05

NUREG-1431 Markup Inserts
ITS SECTION 3.3.8 - Fuel Storage Building Emergency Ventilation System (FSBEVS) Instrumentation

INSERT: 3.3-168-01

Fuel Storage Building Emergency Ventilation System (FSBEVS)

INSERT: 3.3-168-02

FSBEVS actuation instrumentation shall be OPERABLE.

INSERT: 3.3-168-03

During movement of irradiated fuel in the fuel storage building.

INSERT: 3.3-168-04

FSBEVS actuation instrumentation inoperable.

INSERT: 3.3-168-05

OR

A.2 Suspend movement of irradiated fuel in the fuel storage building.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. (continued)	B.2	Place both trains in emergency [radiation protection] mode.	Immediately
C. Required Action and associated Completion Time for Condition A or B not met during movement of irradiated fuel assemblies in the fuel building.	C.1	Suspend movement of irradiated fuel assemblies in the fuel building.	Immediately
D. Required Action and associated Completion Time for Condition A or B not met in MODE 1, 2, 3, or 4.	D.1	Be in MODE 3.	6 hours
	AND		
	D.2	Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

-----NOTE-----
Refer to Table 3.3.8-1 to determine which SRs apply for each FBACS Actuation Function.

SURVEILLANCE		FREQUENCY
SR 3.3.8.1	Perform CHANNEL CHECK.	12 24 hours
SR 3.3.8.2	Perform COT.	92 days

CLB.1

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
~~SR 3.3.8.3~~	~~Perform ACTUATION LOGIC TEST.~~	~~31 days on a STAGGERED TEST BASIS~~
SR 3.3.8.4	----------NOTE---------- Verification of setpoint is not required. ---------- Perform TADOT.	SEE ITS 3.7.11 [18] months
SR 3.3.8.~~5~~ 3	Perform CHANNEL CALIBRATION.	~~[18]~~ 24 months

Table 3.3.8-1 (page 1 of 1)
FBACS Actuation Instrumentation

FUNCTION	APPLICABLE MODES OR SPECIFIED CONDITIONS	REQUIRED CHANNELS	SURVEILLANCE REQUIREMENTS	TRIP SETPOINT
1. Manual Initiation	[1,2,3,4] (a)	2 2	SR 3.3.8.4 SR 3.3.8.4	NA NA
[2. Automatic Actuation Logic and Actuation Relays	1,2,3,4 (a)	2 trains	SR 3.3.8.3	NA]
3. Fuel Building Radiation				
a. Gaseous	[1,2,3,4] (a)	[2]	SR 3.3.8.1 SR 3.3.8.2 SR 3.3.8.5	≤ [2] mR/hr
b. Particulate	[1,2,3,4] (a)	[2]	SR 3.3.8.1 SR 3.3.8.2 SR 3.3.8.5	≤ [2] mR/hr

(a) During movement of irradiated fuel assemblies in the fuel building.

Insert: B 3.3-168-01

B 3.3 INSTRUMENTATION

B 3.3.8 ~~Fuel Building Air Cleanup System (FBACS)~~ Actuation Instrumentation

BASES

BACKGROUND

The ~~FBACS~~ FSBEVS ensures that radioactive materials in the fuel building atmosphere following a fuel handling accident ~~or a loss of coolant accident (LOCA)~~ are filtered and adsorbed prior to exhausting to the environment. The system is described in the Bases for LCO 3.7.13, ~~Fuel Building Air Cleanup System.~~ The system initiates filtered ventilation of the fuel building automatically following receipt of a high radiation signal ~~(gaseous or particulate) or a safety injection (SI) signal.~~ ~~Initiation may also be performed manually as needed from the main control room.~~

Insert: B 3.3-168-01

Insert: B 3.3-168-02

~~High gaseous and particulate radiation, each monitored by either of two monitors, provides FBACS initiation. Each FBACS train is initiated by high radiation detected by a channel dedicated to that train. There are a total of two channels, one for each train. Each channel contains a gaseous and particulate monitor. High radiation detected by any monitor or an SI signal from the Engineered Safety Features Actuation System (ESFAS) initiates fuel building isolation and starts the FBACS. These actions function to prevent exfiltration of contaminated air by initiating filtered ventilation, which imposes a negative pressure on the fuel building. Since the radiation monitors include an air sampling system, various components such as sample line valves, sample line heaters, sample pumps, and filter motors are required to support monitor OPERABILITY.~~

Insert: B 3.3-168-04

FSBEVS

storage

Insert: B 3.3-168-05

APPLICABLE SAFETY ANALYSES

The ~~FBACS~~ FSBEVS ensures that radioactive materials in the fuel building atmosphere following a fuel handling accident ~~or a LOCA~~ are filtered and adsorbed prior to being exhausted to the environment. This action reduces the radioactive content in the fuel building exhaust following a ~~LOCA or~~ fuel handling accident so that offsite doses remain within the limits specified in 10 CFR 100 (Ref. 1).

Insert: B 3.3-168-03

The FBACS actuation instrumentation satisfies Criterion 3 of ~~the NRC Policy Statement.~~ 10 CFR 50.36

(continued)

NUREG-1431 Markup Inserts
ITS SECTION 3.3.8 - Fuel Storage Building Emergency Ventilation System (FSBEVS) Instrumentation

INSERT: B 3.3-168-01

Fuel Storage Building Emergency Ventilation System (FSBEVS)

INSERT: 3.3-168-02

from fuel storage building area radiation monitor, R-5.

INSERT: 3.3-168-03

when the FSBEVS is aligned and operates as described in the Bases for LCO 3.7.13, Fuel Storage Building Emergency Ventilation System (FSBEVS).

INSERT: 3.3-168-04

High radiation levels detected by the fuel storage building area radiation monitor, R-5,

INSERT: 3.3-168-05

Following an Area Radiation Monitor (R-5) signal or manual actuation to the emergency mode of operation, the FSBEVS ventilation supply fans stop automatically and the associated ventilation supply dampers close automatically. The charcoal filter face dampers (inlet and outlet dampers) open automatically, if not already open. Additionally, the rolling door closes, if open, and the inflatable seals on the man doors are actuated. The FSB exhaust fan continues to operate.

BASES (continued)

LCO

The LCO requirements ensure that instrumentation necessary to initiate the FBACS is OPERABLE.

for manual and automatic actuation of the FSBEVS

1. Manual Initiation

The LCO requires two channels OPERABLE. The operator can initiate the FBACS at any time by using either of two switches in the control room. This action will cause actuation of all components in the same manner as any of the automatic actuation signals.

The LCO for Manual Initiation ensures the proper amount of redundancy is maintained in the manual actuation circuitry to ensure the operator has manual initiation capability.

Each channel consists of one push button and the interconnecting wiring to the actuation logic cabinet.

Insert: B 3.3-169-01

2. Automatic Actuation Logic and Actuation Relays

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

Automatic Actuation Logic and Actuation Relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b., SI, in LCO 3.3.2. The applicable MODES and specified conditions for the FBACS portion of these functions are different and less restrictive than those specified for their SI roles. If one or more of the SI functions becomes inoperable in such a manner that only the FBACS function is affected, the Conditions applicable to their SI function need not be entered. The less restrictive Actions specified for inoperability of the FBACS functions specify sufficient compensatory measures for this case.

3. Fuel Building Radiation

The LCO specifies two required Gaseous Radiation Monitor channels and two required Particulate Radiation Monitor channels to ensure that the radiation monitoring instrumentation necessary to initiate the FBACS remains OPERABLE.

(continued)

NUREG-1431 Markup Inserts
ITS SECTION 3.3.8 - Fuel Storage Building Emergency Ventilation System (FSBEVS) Instrumentation

INSERT: B 3.3-169-01

Manual and automatic FSBEVS initiation capability is OPERABLE when the Fuel Storage Building Area Radiation Monitor (R-5) signal or manual actuation to the emergency mode of operation will cause the realignment of the FSBEVS to the accident mode of operation as described in the Bases for LCO 3.7.13, Fuel Storage Building Emergency Ventilation System (FSBEVS).

The setpoint for Fuel Storage Building Area Radiation Monitor (R-5) are established in accordance with the Offsite dose Calculation Manual (ODCM) (Ref. 2).

BASES

LCO

3. Fuel Building Radiation (continued)

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

Only the Trip Setpoint is specified for each FBACS Function in the LCO. The Trip Setpoint limits account for instrument uncertainties, which are defined in the Unit Specific Setpoint Calibration Procedure (Ref. 2).

APPLICABILITY

The manual FBACS initiation must be OPERABLE in MODES [1, 2, 3, and 4] and when moving irradiated fuel assemblies in the fuel building, to ensure the FBACS operates to remove fission products associated with leakage after a LOCA or a fuel handling accident. The automatic FBACS actuation instrumentation is also required in MODES [1, 2, 3, and 4] to remove fission products caused by post LOCA Emergency Core Cooling Systems leakage.

High radiation initiation of the FBACS must be OPERABLE in any MODE during movement of irradiated fuel assemblies in the fuel building to ensure automatic initiation of the FBACS when the potential for a fuel handling accident exists.

While in MODES 5 and 6 without fuel handling in progress, the FBACS instrumentation need not be OPERABLE since a fuel handling accident cannot occur.

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

(continued)

BASES

ACTIONS (continued)

specification. If the Trip Setpoint is less conservative than the tolerance specified by ~~the calibration procedure~~ Reference 2, 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 3.3.8-1 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 A.1 and A.2

Insert: B 3.3-171-01

~~Condition A applies to the actuation logic train function of the Solid State Protection System (SSPS), the radiation monitor functions, and the manual function. Condition A applies to the failure of a single actuation logic train, radiation monitor channel, or manual channel. If one channel or train is inoperable, a period of 7 days is allowed to restore it to OPERABLE status. If the train cannot be restored to OPERABLE status, one FBACS train must be placed in operation. This accomplishes the actuation instrumentation function and places the unit in a conservative mode of operation. The 7 day Completion Time is the same as is allowed if one train of the mechanical portion of the system is inoperable. The basis for this time is the same as that provided in LCO 3.7.13.~~

B.1.1, B.1.2, ~~B.2~~

~~Condition B applies to the failure of two FBACS actuation logic trains, two radiation monitors, or two manual channels. The Required Action is to place one FBACS train in operation immediately. This accomplishes the actuation instrumentation function that may have been lost and places the unit in a conservative mode of operation. The applicable Conditions and Required Actions of LCO 3.7.13 must also be entered for the FBACS train made inoperable by the inoperable actuation instrumentation. This ensures appropriate limits are placed on train inoperability as discussed in the Bases for LCO 3.7.13.~~

(continued)

NUREG-1431 Markup Inserts
ITS SECTION 3.3.8 - Fuel Storage Building Emergency Ventilation System (FSBEVS) Instrumentation

INSERT: B 3.3-171-01

This Condition applies when the manual or automatic FSBEVS initiation capability is inoperable. The Required Action is to immediately place the system in operation as described in the Bases for LCO 3.7.13, FSBEVS. This accomplishes the actuation instrumentation function that may have been lost and places the unit in a accident mode of operation. Alternatively, movement of irradiated fuel assemblies in the fuel building must be suspended immediately to eliminate the potential for events that could require FSBEVS actuation. The Completion Time of immediately requires that the Required Action be pursued without delay and in a controlled manner.

BASES

ACTIONS

B.1.1, B.1.2, B.2 (continued)

Alternatively, both trains may be placed in the emergency [radiation protection] mode. This ensures the FBACS Function is performed even in the presence of a single failure.

C.1

Condition C applies when the Required Action and associated Completion Time for Condition A or B have not been met and irradiated fuel assemblies are being moved in the fuel building. Movement of irradiated fuel assemblies in the fuel building must be suspended immediately to eliminate the potential for events that could require FBACS actuation.

D.1 and D.2

Condition D applies when the Required Action and associated Completion Time for Condition A or B 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.

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that Table 3.3.8-1 determines which SRs apply to which FBACS Actuation Functions.

SR 3.3.8.1

Performance of the CHANNEL CHECK once every 12 24 hours ensures that a gross failure of instrumentation has not occurred. 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.8.1 (continued)

~~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.

Insert: B3.3-173-01

~~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.~~ not

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

SR 3.3.8.2

for both the manual and automatic function

A COT is performed once every 92 days ~~on each required channel~~ to ensure the entire channel will perform the intended function. This test verifies the capability of the instrumentation to provide the FBACS actuation. The setpoints shall be left consistent with ~~the unit specific calibration procedure tolerance~~. The Frequency of 92 days is based on the known reliability of the monitoring equipment and has been shown to be acceptable through operating experience.

requirements of Reference 2

This test is typically performed in conjunction with SR 3.7.13.4 which verifies OPERABILITY of the actuated devices.

~~SR 3.3.8.3~~

~~SR 3.3.8.3 is the performance of an ACTUATION LOGIC TEST. The actuation logic is tested every 31 days on a STAGGERED TEST BASIS. All possible logic combinations, with and without applicable permissives, are tested for each protection function. The Frequency is based on the known~~

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.8.3 (continued)

reliability of the relays and controls and the multichannel redundancy available, and has been shown to be acceptable through operating experience.

SR 3.3.8.4 SEE SR 3.7.13.4

SR 3.3.8.4 is the performance of a TADOT. This test is a check of the manual actuation functions and is performed every [18] months. Each manual actuation function is tested up to, and including, the master relay coils. In some instances, the test includes actuation of the end device (e.g., pump starts, valve cycles, etc.). The Frequency is based on operating experience and is consistent with the typical industry refueling cycle. The SR is modified by a Note that excludes verification of setpoints during the TADOT. The Functions tested have no setpoints associated with them.

SR 3.3.8.5 3

A CHANNEL CALIBRATION is performed every 18 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 is based on operating experience and is consistent with the typical industry refueling cycle.

REFERENCES

1. 10 CFR 100.11.
2. Unit Specific Setpoint Calibration Procedure. IP3 Offsite Dose Calculation Manual

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.3.8:

"Fuel Storage Building Emergency Ventilation System (FSBEVS) Instrumentation"

PART 6:

Justification of Differences between

NUREG-1431 and IP3 ITS

JUSTIFICATION OF DIFFERENCES FROM NUREG-1431
ITS SECTION 3.3.8 - FUEL STORAGE BUILDING EMERGENCY VENTILATION SYSTEM (FSBEVS) INSTRUMENTATION

CLB.1 NUREG-1431, Rev 1, Section 3.3.8, was modified as needed to reflect the IP3 design and current licensing basis. A detailed description of the design, accident analysis assumptions, and Operability requirements are incorporated into the IP3 ITS Bases. These changes maintain the IP3 current licensing basis except as identified and justified in the CTS/ITS discussion of changes.

PLANT-SPECIFIC WORDING PREFERENCE OR MINOR EDITORIAL IMPROVEMENT

PA.1 Corrected typographical error or made a minor editorial improvement to improve clarity and ensure requirements are fully understood and consistently applied. There are no technical changes to requirements as specified in NUREG 1431, Rev. 1; therefore, this change is not a significant or generic deviation from NUREG 1431, Rev 1.

PLANT-SPECIFIC DIFFERENCE IN THE DESIGN OR DESIGN BASIS

DB.1 Design or implementation details are incorporated or revised as necessary to more precisely describe IP3 current design or practice. These changes are intended to describe the design, improve clarity, or ensure requirements are fully understood and consistently applied. Unless identified and described blow, these changes are self-explanatory. A detailed description of the design, accident analysis assumptions, and Operability requirements are incorporated into the IP3 ITS Bases. These changes maintain the IP3 current licensing basis except as identified and justified in the CTS/ITS discussion of changes.

DIFFERENCE BASED ON A GENERIC CHANGE TRAVELER FOR NUREG-1431

None

DIFFERENCE FOR ANY REASON OTHER THAN ABOVE

None

Indian Point 3

Improved

Technical Specifications

Conversion Submittal

Volume 7

New York Power Authority

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.1:

"RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits"

PART 1:

Indian Point 3
Improved Technical Specifications and Bases

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.1 RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits

LCO 3.4.1 RCS DNB parameters for pressurizer pressure, RCS average temperature, and RCS total flow rate shall be within the limits specified below:

a. Pressurizer pressure ≥ 2205 psig;

b. RCS average loop temperature ≤ 571.5°F; and

c. RCS total flow rate ≥ 375,600 gpm.

APPLICABILITY: MODE 1.

----------NOTE----------
Pressurizer pressure limit does not apply during:

a. THERMAL POWER ramp > 5% RTP per minute; or

b. THERMAL POWER step > 10% RTP.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more RCS DNB parameters not within limits.	A.1	Restore RCS DNB parameter(s) to within limit.	2 hours
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 2.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.1.1	Verify pressurizer pressure is ≥ 2205 psig.	12 hours
SR 3.4.1.2	Verify RCS average loop temperature is ≤ 571.5°F.	12 hours
SR 3.4.1.3	Verify RCS total flow rate is ≥ 375,600 gpm.	12 hours
SR 3.4.1.4	----------NOTE---------- Not required to be performed until 24 hours after ≥ 90% RTP. ---------- Verify by precision heat balance that RCS total flow rate is ≥ 375,600 gpm.	24 months

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.1 RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits

BASES

BACKGROUND

These Bases address requirements for maintaining RCS pressure, temperature, and flow rate within limits assumed in the safety analyses. The safety analyses (Ref. 1) of normal operating conditions and anticipated operational occurrences assume initial conditions within the normal steady state envelope. The limits placed on RCS pressure, temperature, and flow rate ensure that the minimum departure from nucleate boiling ratio (DNBR) will be met for each of the transients analyzed.

The RCS pressure limit is consistent with operation within the nominal operational envelope. Pressurizer pressure indications are averaged to come up with a value for comparison to the limit. A lower pressure will cause the reactor core to approach DNB limits.

The RCS coolant average loop temperature limit is consistent with full power operation within the nominal operational envelope. RCS average temperature is determined by calculating the average temperature for each loop and then calculating the average of these average loop temperatures and this average of the averages is compared to the acceptance criteria. A higher average temperature will cause the core to approach DNB limits.

The RCS flow rate normally remains constant during an operational fuel cycle with all pumps running. The minimum RCS flow limit corresponds to that assumed for DNB analyses. RCS flow rate is determined by calculating the average flow rate for each loop and then calculating the sum of these average loop flow rates and this sum of the averages is compared to the acceptance criteria. A lower RCS flow will cause the core to approach DNB limits.

Operation for significant periods of time outside these DNB limits increases the likelihood of a fuel cladding failure in a DNB limited event.

BASES

BACKGROUND (Continued)

Calculations have shown that reactor heat equivalent to 10% rated power can be removed via the steam generators with natural circulation without violating DNBR limits. This analysis assumed conservative flow resistances including steam generator tube plugging and a locked rotor in each loop (Ref. 1).

APPLICABLE SAFETY ANALYSES

The requirements of this LCO represent the initial conditions for DNB limited transients analyzed in the plant safety analyses (Ref. 1). The safety analyses have shown that transients initiated from the limits of this LCO will result in meeting the DNBR acceptance limit for the RCS DNB parameters. Changes to the unit that could impact these parameters must be assessed for their impact on the DNBR criteria. The transients analyzed include loss of coolant flow events and dropped or stuck rod events. A key assumption for the analysis of these events is that the core power distribution is within the limits of LCO 3.1.6, "Control Bank Insertion Limits"; LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)"; and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)."

LCO

This LCO specifies limits on the monitored process variables (i.e., pressurizer pressure, RCS average loop temperature, and RCS total flow rate, to ensure the core operates within the limits assumed in the safety analyses. Operating within these limits will result in meeting the DNBR criterion in the event of a DNB limited transient.

The RCS total flow rate limit of 375,600 gpm allows a measurement uncertainty of 2.9% associated with the performance of Reactor coolant System Flow Calculation.

The pressurizer pressure limit of 2205 psig includes the allowance for measurement uncertainty and instrument error.

BASES

LCO (continued)

The limit on RCS average loop temperature provides assurance that RCS temperatures are maintained within the normal steady state envelope of operation assumed in the safety analyses performed to support the Vantage + fuel reloads with asymmetric tube plugging among steam generators. A maximum full power Tcold of 547.7°F (including control deadband and measurement uncertainties) was assumed in these safety analyses. A Tavg of 578.3°F assures that a Tcold of 547.7°F is not exceeded at a measured flow of ≥ 375,600 gpm when considering asymmetric tube plugging among steam generators for DNB considerations. Therefore, the LCO limit of 571.5°F for RCS average loop temperature, which is based on meeting analysis assumptions for post-LOCA containment integrity, conservatively ensures that DNBR limits are met.

The RCS DNB parameters satisfy Criterion 2 of 10 CFR 50.36.

APPLICABILITY

In MODE 1, the limits on pressurizer pressure, RCS coolant average temperature, and RCS flow rate must be maintained during steady state operation in order to ensure DNBR criteria will be met in the event of an unplanned loss of forced coolant flow or other DNB limited transient. In all other MODES, the power level is low enough that DNB is not a concern.

A Note has been added to indicate the limit on pressurizer pressure is not applicable during short term operational transients such as a THERMAL POWER ramp increase > 5% RTP per minute or a THERMAL POWER step increase > 10% RTP. These conditions represent short term perturbations where actions to control pressure variations might be counterproductive. Also, since they represent transients initiated from power levels < 100% RTP, an increased DNBR margin exists to offset the temporary pressure variations.

Another set of limits on DNB related parameters is provided in SL 2.1.1, "Reactor Core SLs." Those limits are less restrictive than the limits of this LCO, but violation of a Safety Limit (SL) merits a stricter, more severe Required Action. Should a

BASES

APPLICABILITY (continued)

violation of this LCO occur, the operator must check whether or not an SL may have been exceeded.

ACTIONS

A.1

RCS pressure and RCS average loop temperature are controllable and measurable parameters. With one or both of these parameters not within LCO limits, action must be taken to restore parameter(s).

RCS total flow rate is not a controllable parameter and is not expected to vary during steady state operation. If the indicated RCS total flow rate is below the LCO limit, power must be reduced, as required by Required Action B.1, to restore DNB margin and eliminate the potential for violation of the accident analysis bounds.

The 2 hour Completion Time for restoration of the parameters provides sufficient time to adjust plant parameters, to determine the cause for the off normal condition, and to restore the readings within limits, and is based on plant operating experience.

B.1

If Required Action A.1 is not met 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 2 within 6 hours. In MODE 2, the reduced power condition eliminates the potential for violation of the accident analysis bounds. The Completion Time of 6 hours is reasonable to reach the required plant conditions in an orderly manner.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1

Since Required Action A.1 allows a Completion Time of 2 hours to restore parameters that are not within limits, the 12 hour Surveillance Frequency for pressurizer pressure is sufficient to ensure the pressure can be restored to a normal operation, steady state condition following load changes and other expected transient operations. Pressurizer pressure indications are averaged to determine the value for comparison to the LCO limit. The 12 hour interval has been shown by operating practice to be sufficient to regularly assess for potential degradation and to verify operation is within safety analysis assumptions.

SR 3.4.1.2

Since Required Action A.1 allows a Completion Time of 2 hours to restore parameters that are not within limits, the 12 hour Surveillance Frequency for RCS average loop temperature is sufficient to ensure the temperature can be restored to a normal operation, steady state condition following load changes and other expected transient operations. RCS average loop temperature is determined by calculating the average temperature for each loop and then calculating the average of these average loop temperatures and this average of the averages is compared to the acceptance criteria. The 12 hour interval has been shown by operating practice to be sufficient to regularly assess for potential degradation and to verify operation is within safety analysis assumptions.

SR 3.4.1.3

The 12 hour Surveillance Frequency for RCS total flow rate is performed using the installed flow instrumentation. The 12 hour interval has been shown by operating practice to be sufficient to regularly assess potential degradation and to verify operation within safety analysis assumptions.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.1.4

Measurement of RCS total flow rate by performance of a precision calorimetric heat balance once every 24 months verifies that the actual RCS flow rate is greater than or equal to the minimum required RCS flow rate.

The Frequency of 24 months reflects the importance of verifying flow after a refueling outage when the core has been altered, SG tubes plugged or other activities performed, which may have caused an alteration of flow resistance.

This SR is modified by a Note that allows entry into MODE 1, without having performed the SR, and placement of the unit in the best condition for performing the SR. The Note states that the SR is not required to be performed until 24 hours after ≥ 90% RTP. This exception is appropriate since the heat balance requires the plant to be at a minimum of 90% RTP to obtain the stated RCS flow accuracies. The Surveillance shall be performed within 24 hours after reaching 90% RTP.

REFERENCES

1. FSAR, Section 14.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.1:

"RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits"

PART 2:

CURRENT TECHNICAL SPECIFICATION PAGES

Annotated to show differences between CTS and ITS

CTS pages and associated TSCRs annotated for this ITS Specification :

CTS Page No.	Effective Amendment	Annotated Amendment	TSCR No.	TSCR Description	ITS Status of TSCR
3.1-36	175	175	No TSCRs	No TSCRs for this Page	N/A
3.1-37	175	175	No TSCRs	No TSCRs for this Page	N/A
3.1-38	175	175	No TSCRs	No TSCRs for this Page	N/A
3.1-39	170	170	No TSCRs	No TSCRs for this Page	N/A
T 4.1-1(1)	170 TSCR 98-043	170 TSCR 98-043	IPN 98-043	Instrument Channel Surveillance Intervals Extended to 24 Months	Incorporated
T 4.1-1(6)	181 TSCR 98-043	181 TSCR 98-043	IPN 98-043	Instrument Channel Surveillance Intervals Extended to 24 Months	Incorporated
4.3-4	175	175	No TSCRs	No TSCRs for this Page	N/A

A.1 A.2

~~3.1~~ Reactor Coolant System (RCS)

LCO 3.4.1 ~~H.~~ RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits*

Specification

Mode 1 A.1

LCO 3.4.1 ~~1.~~ During ~~the POWER OPERATION CONDITION~~, RCS DNB parameters for pressurizer pressure and RCS average temperature shall be within the limits specified below:

LCO 3.4.1.a ~~a.~~ Pressurizer pressure ≥ 2205 psig; A.7

LCO 3.4.1.b ~~b.~~ ~~Maximum indicated~~ T_{avg} ≤ 571.5°F; and Mode 1 A.1

~~2.~~ ~~At the POWER OPERATION CONDITION~~ with ~~four reactor coolant pumps running~~ the RCS DNB parameter for RCS total flow rate shall be within the following limit: A.3

LCO 3.4.1.c RCS total flow rate ≥ 375,600 gpm.

3.4.1 Applicability Note

~~3.~~ The pressurizer pressure limit of Specification ~~3.1.H.1~~ does not apply during:

~~a.~~ THERMAL POWER ramp > 5% RTP per minute; or

b. THERMAL POWER step > 10% RTP.

3.4.1, Req Act A.1

~~4.~~ If pressurizer pressure, RCS average temperature, or RCS total flow rate are not in accordance with Specifications 3.1.H.1, 3.1.H.2, or 3.1.H.3, then, ~~immediately verify that the safety limits of Specification 2.1 have not been exceeded and~~ within 2 hours, restore the RCS DNB parameter(s) to within limits. A.4

Req Act B.1

~~5.~~ If pressurizer pressure and/or RCS average temperature are not restored to within limits within 2 hours, be in the ~~HOT SHUTDOWN CONDITION~~ Mode 2 within 6 hours. L.1

Req Act B.1

~~6.~~ If RCS total flow rate is not restored to within the limits of Specification 3.1.H.2 within 2 hours, bring ~~THERMAL POWER~~ to ~~< 10% RTP~~ within 6 hours ~~and ensure operation is in accordance with Specification 3.1.A.1.e~~ M.1

Surveillance Requirements

~~Reference Technical Specification Table 4.1-1, Items 4, 5, and 7, and Section 4.3.B.~~ A.1

Bases

~~**Background**~~

~~These Bases address requirements for maintaining RCS pressure, temperature, and flow rate within limits assumed in the safety analyses. The safety analyses (Ref. 1) of normal operating conditions and anticipated operational occurrences assume initial conditions within the normal steady state envelope. The limits placed on RCS~~ A.1

~~* Current DNB analysis contains adequate margin for Cycle 10. Prior to achieving criticality in Cycle 11, the DNB analysis must be reviewed and approved by NRC staff.~~ A.6

A.1

3.1.H (continued)

pressure, temperature, and flow rate ensure that the minimum departure from nucleate boiling ratio (DNBR) will be met for each of the transients analyzed.

The RCS pressure and temperature limits are consistent with operation within the nominal operational envelope. A lower pressure will cause the reactor core to approach DNB limits. A higher RCS average temperature will cause the core to approach DNB limits.

The RCS flow rate normally remains constant during an operational fuel cycle with all pumps running. The minimum RCS flow limit bounds that assumed for DNB analyses. Flow rate indications are averaged to come up with a value for comparison to the limit. A lower RCS flow will cause the core to approach DNB limits.

Operation for significant periods of time outside these DNB limits increases the likelihood of a fuel cladding failure in a DNB limited event.

Applicable Safety Analyses

The requirements of this Specification represent the initial conditions for DNB limited transients analyzed in the plant safety analyses (Ref. 1). The safety analyses have shown that transients initiated from the limits of this Specification will result in meeting the applicable DNBR criteria. Changes to the unit that could affect these parameters must be assessed for their effect on the DNBR criteria.

Specification

Specifications 3.1.H.1 and 3.1.H.2 specify limits on the monitored process variables (pressurizer pressure, RCS average temperature, and RCS total flow rate) to ensure that the core operates within the limits assumed in the safety analyses. Operating within these limits will result in meeting the DNBR criterion in the event of a DNB limited transient.

The RCS total flow rate limit of 375,600 gpm allows for a measurement uncertainty of 2.9% associated with the performance of Reactor Coolant System Flow Calculation required by Technical Specification 4.3.B. Because the flow instrumentation provides flow indication based on a percentage of full flow, the 375,600 gpm is converted into a percentage of full flow to accomodate the verification that RCS total flow is within limits during channel checks.

The pressurizer pressure limit of 2205 psig allows for measurement uncertainty and instrument error. Pressurizer pressure indications are averaged to come up with a value for comparison to the limit.

The limit on maximum indicated RCS average temperature provides assurance that RCS temperatures are maintained within the normal steady state envelope of operation assumed in the safety analyses performed to support the Vantage + fuel reloads with asymmetric tube

3.1.H (continued)

A.1

plugging among steam generators. A maximum full power T_{cold} of 547.7°F (including control deadband and measurement uncertainties) was assumed in these safety analyses. A T_{avg} of 578.3°F assures that a T_{cold} of 547.7°F is not exceeded at a measured flow of ≥ 375,600 gpm when considering asymmetric tube plugging among steam generators for DNB considerations. However, T_{avg} will be controlled to a maximum indicated T_{avg} of 571.5°F which assures consistency with analyses for post-LOCA containment integrity.

Applicability

During the POWER OPERATION CONDITION, the limits on pressurizer pressure and RCS coolant average temperature must be maintained during steady state operation in order to ensure DNBR criteria will be met in the event of an unplanned loss of forced coolant flow or other DNB limited transient. For the same reason, during the POWER OPERATION CONDITION with four reactor coolant pumps running, the limit on RCS flow rate must be maintained. In all other operating conditions, the power level is low enough that DNB is not a concern.

Specification 3.1.H.3 indicates that the limit on pressurizer pressure is not applicable during short term operational transients such as a THERMAL POWER ramp increase > 5% RTP per minute or a THERMAL POWER step increase > 10% RTP. These conditions represent short term perturbations where actions to control pressure variations might be counter productive. Also, since they represent transients initiated from power levels < 100% RTP, an increased DNBR margin exists to offset the temporary pressure variations.

Another set of limits on DNB related parameters is provided in Safety Limit 2.1, "Safety Limits, Reactor Core." Those limits are less restrictive than the limits of this specification but violation of a Safety Limit merits stricter, more severe required action. Should a violation of Specification 3.1.H.1 occur, the operator must check whether or not a Safety Limit has been exceeded.

Actions

RCS pressure and RCS average temperature are controllable and measurable parameters. With one or both of these parameters not within specification limits, action must be taken to restore the parameter(s).

The 2 hour completion time for restoration of the parameters provides sufficient time to adjust plant parameters, to determine the cause for the off normal condition, and to restore the readings within limits, and is based on plant operating experience for Westinghouse plants.

If the required action of Specification 3.1.H.4 is not met within the associated completion time, the plant must be brought to a mode in which Specification 3.1.H.1 does not apply. To achieve this status, the plant must be brought to at least the HOT SHUTDOWN CONDITION within 6 hours. The reduced power condition eliminates the potential for violation of the accident analysis bounds. The completion time of 6 hours is reasonable to reach the required plant conditions in an orderly manner.

3.1.H (continued)

A.1

RCS total flow rate is not a controllable parameter and is not expected to vary during steady state operation. If the indicated RCS total flow rate is below the specification limit, power must be reduced, as required by Specification 3.1.H.6, to restore DNB margin and eliminate the potential for violation of the accident analysis bounds. In accordance with Specification 3.1.A.1.f, four reactor coolant pumps must be in operation when Thermal Power is greater than 10% RTP. Therefore, power may be reduced to less than or equal to 10% power if RCS total flow rate is not in accordance with Specification 3.1.H.2. However, it must be verified that operation is in accordance with Specification 3.1.A.1.e which requires at least two reactor coolant pumps to be in operation for Thermal Power greater than 2% RTP.

Surveillance Requirements

A note to Table 4.1-1 requires verification that pressurizer pressure, RCS average temperature, and RCS total flow rate are within the limits of this technical specification (3.1.H). This is required to be performed once per shift.

The frequency for the surveillance for pressurizer pressure is sufficient to ensure the pressure can be restored to a normal operation, steady state condition following load changes and other expected transient operations. A 12 hour interval has been shown by operating practice to be sufficient to regularly assess for potential degradation and to verify that operation is within safety analysis assumptions.

The frequency for the surveillance for RCS average temperature is sufficient to ensure the temperature can be restored to a normal operation, steady state condition following load changes and other expected transient operations. A 12 hour interval has been shown by operating practice to be sufficient to regularly assess for potential degradation and to verify that operation is within safety analysis assumptions.

The surveillance for RCS total flow rate is performed using the installed flow instrumentation. A 12 hour interval has been shown by operating practice to be sufficient to regularly assess potential degradation and to verify that operation is within safety analysis assumptions.

References

1. FSAR Chapter 14, "Safety Analysis"

TABLE 4.1-1 (Sheet 1 of 6)

MINIMUM FREQUENCIES FOR CHECKS, CALIBRATIONS AND TESTS OF INSTRUMENT CHANNELS

	Channel Description	Check	Calibrate	Test	Remarks
	1. Nuclear Power Range	S	D (1) M (3)*	Q (2)** Q (4)	1) Heat balance calibration 2) Bistable action (permissive, rod stop, trips) 3) Upper and lower chambers for axial offset 4) Signal to Δ T
	2. Nuclear Intermediate Range	S (1)	N.A.	P (2)	1) Once/shift when in service 2) Verification of channel response to simulated inputs
	3. Nuclear Source Range	S (1)	N.A.	P (2)	1) Once/shift when in service 2) Verification of channel response to simulated inputs
SR 3.4.1.2	4. Reactor Coolant Temperature	S ## (2)	24M	Q (1)	1) Overtemperature ΔT, overpower ΔT, and low T_{avg} 2) Normal instrument check interval is once/shift T_{avg} instrument check interval reduced to every 30 minutes when: - T_{avg}-T_{ref} deviation and low T_{avg} alarms are not reset and, - Control banks are above 0 steps
SR 3.4.1.3	5. Reactor Coolant Flow	S ##	24M	Q	
	6. Pressurizer Water Level	S	18M	Q	
SR 3.4.1.1	7. Pressurizer Pressure	S ##	24M	Q	High and Low

SEE ITS 3.3.1

SEE ITS 3.4.2

Amendment No. 38, 68, 74, 93, 107, 128, 126, 137, 140, 149, 150, 168, 170

ITS 3.4.1

Deleted by TSCR 98-043

Table Notation

* By means of the movable incore detector system

** Quarterly when reactor power is below the setpoint and prior to each startup if not done previous month.

*** ~~This surveillance requirement may be extended on a one time basis to no later than April 26, 1997.~~

**** ~~This surveillance requirement may be extended on a one time basis to no later than May 12, 1997.~~

***** ~~This surveillance requirement may be extended on a one time basis to no later than May 14, 1997.~~

\# These requirements are applicable when specification 3.3.F.5 is in effect only.

The "each shift" frequency also requires verification that the DNB parameters (Reactor Coolant Temperature, Reactor Coolant Flow, and Pressurizer Pressure) are within the limits of Technical Specification 3.1.H.

SR 3.4.1.1
SR 3.4.1.2
SR 3.4.1.3

S - Each Shift (i.e., at least once per 12 hours)
W - Weekly
P - Prior to each startup if not done previous week
M - Monthly
NA - Not Applicable
Q - Quarterly
D - Daily
18M - At least once per 18 months
TM - At least every two months on a staggered test basis (i.e., one train per month)
24M - At least once per 24 months
6M - At least once per 6 months

4.3 REACTOR COOLANT SYSTEM (RCS) TESTING

B. Reactor Coolant System Flow Calculation

Specification

precision heat balance — A.5

SR 3.4.1.4 & Note

Once every 24 months, prior to exceeding 24 hours of continuous operation with THERMAL POWER ≥ 90% RTP, verify by flow calculation that RCS total flow rate is ≥ 375,600 gpm.

Basis

Measurement of RCS total flow rate by performance of a flow calculation once every 24 months verifies that the actual RCS flow rate is greater than or equal to the minimum required RCS flow rate.

The frequency of 24 months reflects the importance of verifying flow after a refueling outage when the core has been altered or steam generator tubes have been plugged, which may have caused an alteration of flow resistance.

This specification allows for placement of the unit in the best condition for performing the Surveillance Requirement. The specification allows the Surveillance Requirement to be performed within 24 hours after THERMAL POWER ≥ 90% RTP. This is appropriate because a flow calculation performed with the plant ≥ 90% RTP will ensure that instrument inaccuracies are consistent with those assumed in the accident analyses. The Surveillance shall be performed within 24 hours of continuous operation at or above 90% RTP.

A.1

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.1:

"RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits"

PART 3:

DISCUSSION OF CHANGES

Differences between CTS and ITS

DISCUSSION OF CHANGES
ITS SECTION 3.4.1 - RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits

ADMINISTRATIVE

A.1 In the conversion of the Indian Point Unit 3 Current Technical Specifications (CTS) to the plant specific Improved Technical Specifications (ITS) certain wording preferences or conventions are adopted which do not result in technical changes (either actual or interpretational). Additionally, editorial changes, reformatting, and revised numbering are adopted to make ITS consistent with the conventions in NUREG-1431, Standard Technical Specifications, Westinghouse Plants, Rev. 1, i.e., the improved Standard Technical Specifications.

The CTS Bases are deleted and replaced with comprehensive ITS Bases designed to support interpretation and implementation of the associated Technical Specifications. The Bases explain, clarify, and document the reasons (i.e., bases) for the associated Technical Specifications, and reflect the IP3 plant specific design, analyses, and licensing basis. In accordance with 10 CFR 50.36(a), the ITS Bases are included with the proposed ITS conversion application; however, deletion of the CTS Bases and the adoption of the ITS Bases is an administrative change with no impact on safety.

A.2 CTS Limiting Conditions for Operation (LCOs) and Surveillance Requirements (SRs) include statements of the objective and the applicability. The CTS statements of objective and applicability are deleted because these statements do not establish any requirements and do not provide any guidance for the application of CTS requirements. Therefore, deletion of these statements has no significant adverse impact on safety.

A.3 CTS 3.1.H.2 specifies that reactor coolant system (RCS) total flow during power operation (Mode 1) must be greater than or equal to 375,600 gpm "with four reactor coolant pumps running." ITS LCO 3.4.1.c specifies the same minimum RCS flow requirements but does not specify that this minimum is applicable only when four RCPs are running. This

detail is not included in the ITS because ITS LCO 3.4.4 already requires that four RCS loops are operable and in operation when in Modes 1 or 2. Additionally, achieving the specified flow rate requires four RCPs in operation. This is an administrative change with no adverse impact on safety.

A.4 CTS 3.1.H.4 specifies that if the RCS pressure, temperature or flow limits of CTS 3.1.H are exceeded, then the safety limits of specification 2.1 must be verified. ITS 3.4.1, Required Actions, do not specify this requirement. Not including a specific requirement to verify SLs are met when LCO 3.4.1 limits are not met is acceptable because ITS SL 2.1.1, Reactor Core SLs, are less restrictive than the limits of ITS LCO 3.4.1 and ITS SL 2.1.1 already specify Actions if SLs are violated (i.e., restore compliance and be in Mode 3 within 1 hour). Additionally, ITS 3.4.1 Bases specify that safety limits for DNB related parameters are provided in ITS SL 2.1.1 and that the operator must check whether or not an SL may have been exceeded if LCO 3.4.1 limits are not met. Therefore, this is an administrative change with no impact on safety.

A.5 CTS 4.3.B requires verification by "flow calculation" every 24 months that RCS total flow rate is within required limits. ITS SR 3.4.1.4 maintains this requirement except that the ITS specifies use of a precision calorimetric heat balance. This is an administrative change with no adverse impact on safety because a precision calorimetric heat balance is a specific description of the intent of the flow calculation required by CTS 4.3.B.

A.6 CTS 3.1.H, RCS Pressure, Temperature and Flow DNB Limits, is modified by a footnote stating that the limits specified in Amendment 175 contain adequate margin for Cycle 10 but that the DNB analysis must be reviewed and approved by the NRC staff prior to Cycle 11. This detail is not included in the ITS because a reminder to complete and submit required core reload reports and development of required Technical Specification

changes is typically not included in the Technical Specifications. This is an administrative change with no adverse impact on safety.

A.7 CTS 3.1.H.1.b specifies a limit on the "maximum indicated" Tavg. ITS LCO 3.4.1.b and ITS SR 3.4.1.2 maintain this limit on the reactor coolant system average temperature with a clarification in the ITS Bases that RCS average temperature is determined by taking the average of the indicated Tavg for each of the four loops. This is an administrative change with no impact on safety because the combination of the ITS LCO 3.4.1.b and ITS SR 3.4.1.2 requirements with the Bases clarification provides a more definitive description of the existing CTS requirement.

MORE RESTRICTIVE

M.1 CTS 3.1.H.6 requires reducing reactor power to ≤ 10% if minimum RCS flow requirements (CTS 3.1.H.2) cannot be met and requires verification that at least two reactor coolant pumps in operation (CTS 3.1.A.1.e). Under the same conditions (minimum RCS flow requirement not met), ITS 3.4.1, Required Action B.1, requires reducing reactor power to ≤ 5% (Mode 2); and, ITS LCO 3.4.4 requires four RCS loops operable and in operation when in Modes 1 or 2 (See ITS 3.4.4).

This change is needed because safety analyses for Mode 1 and 2 contain the implicit assumption of 4 RCPs in operation as part of the DBA initial conditions. This change is acceptable because reducing reactor power to ≤ 5% (i.e., Mode 2) is adequate to ensure that departure from nucleate boiling ratio (DNBR) criteria will not be exceeded during an unplanned loss of forced coolant flow or other DNB limited transient even when reactor coolant flow is not within limits with 4 RCPs in operation. This more restrictive change is acceptable because it does not introduce any operation that is un-analyzed while requiring a more conservative response than is currently required when RCS flow is not within required limits. Therefore, this change has no significant adverse impact on safety.

DISCUSSION OF CHANGES
ITS SECTION 3.4.1 - RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits

LESS RESTRICTIVE

L.1 CTS 3.1.H.5 requires that the reactor be placed in Hot Shutdown (Mode 3) if RCS limits for pressure and temperature are not met and not restored within 2 hours.

Under the same conditions (RCS pressure and temperature limits not met), ITS 3.4.1, Required Action B.1, only requires reducing reactor power to ≤ 5% (Mode 2). This change is acceptable because lower power levels increase the margin to DNBR limits and operation with 4 RCPs in operation (as required by ITS LCO 3.4.4) but less than 5% reactor power is sufficient to eliminate the potential for violation of DNBR limits in the event of an unplanned loss of forced coolant flow or other DNB limited transient. Additionally, the ITS LCO 3.4.4 requirement for 4 RCPs in Operation in Modes 1 and 2 provides assurance that RCS flow will be consistent with the accident analysis. Therefore, this change has no adverse impact on safety.

REMOVED DETAIL

None

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.1:

"RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits"

PART 4:

No Significant Hazards Considerations for Changes between CTS and ITS that are Less Restrictive

No Significant Hazard Considerations for Changes that are Administrative, More Restrictive, and Removed Details are the same for all Packages. A Copy is included at the end of the Package.

NO SIGNIFICANT HAZARDS EVALUATION
ITS SECTION 3.4.1 - RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits

LESS RESTRICTIVE
("L.1" Labeled Comments/Discussions)

New York Power Authority has evaluated the proposed Technical Specification change identified as "Less Restrictive" in accordance with the criteria set forth in 10 CFR 50.92, and has determined that the proposed change does not involve a significant hazards consideration. The bases for the determination that the proposed changes do not involve a significant hazards consideration are discussed below.

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

   This change requires that the reactor is placed in Mode 2 (reactor power to ≤ 5%) instead of Mode 3 (Hot Shutdown) 3 when RCS limits for pressure and temperature are not met and not restored within 2 hours. This change will not result in a significant increase in the probability of an accident previously evaluated because maintaining the reactor in Mode 2 or Mode 3 when RCS limits for pressure and temperature are not met has no affect on the initiators of any analyzed events.

   This change will not result in a significant increase in the consequences of an accident previously evaluated because lower power levels increase the margin to DNBR limits and operation with 4 RCPs in operation (as required by ITS LCO 3.4.4) but less than 5% reactor power is sufficient to eliminate the potential for violation of DNBR limits in the event of an unplanned loss of forced coolant flow or other DNB limited transient. Additionally, the ITS LCO 3.4.4 requirement for 4 RCPs in Operation in Modes 1 and 2 provides assurance that RCS flow will be consistent with the accident analysis.

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

   The proposed changes will not involve any physical changes to plant systems, structures, or components (SSC). The changes in normal Plant operation are consistent with the current safety analysis assumptions

because there is no change in the way the reactor is are operated. Therefore, these changes will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

This change does not involve a significant reduction in a margin of safety because lower power levels increase the margin to DNBR limits and operation with 4 RCPs in operation (as required by ITS LCO 3.4.4) but less than 5% reactor power is sufficient to eliminate the potential for violation of DNBR limits in the event of an unplanned loss of forced coolant flow or other DNB limited transient. Additionally, the ITS LCO 3.4.4 requirement for 4 RCPs in Operation in Modes 1 and 2 provides assurance that RCS flow will be consistent with the accident analysis.

Indian Point 3
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Technical Specification 3.4.1:

"RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits"

PART 5:

NUREG-1431
Annotated to show differences between NUREG-1431 and ITS

Status of NUREG 1431 Generic Changes for ITS 3.4.1

This ITS Specification is based on NUREG-1431 Specification No. **3.4.1**
as modified by the following Generic Changes:

OG No.	TSTF No.	Generic Change Description	NRC STATUS	IP3 STATUS	JD No.
WOG-021		CLARIFY THAT THE APPLICABILITY NOTE TO DNB PARAMETERS ONLY APPLIES DURING PRESSURE TRANSIENTS	Rejected by TSTF	Not Incorporated	**N/A**
WOG-037 R1	**105 R1**	REMOVE THE DETAILS OF PERFORMING AN RCS FLOW MEASUREMENT	NRC Rejects: TSTF to Revise	Not Incorporated	**N/A**
WOG-059	**136 R0**	COMBINE LCO 3.1.1 AND 3.1.2	Approved by NRC	Incorporated	**T.1**
WOG-099		EXTEND THE TIME ALLOWED TO PERFORM THE BOC PRECISION RCS FLOW RATE MEASUREMENT	TSTF Review	Incorporated	**N/A**

3.4 REACTOR COOLANT SYSTEM (RCS)

<CTS> 3.4.1 RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits

<3.1.H.1> <3.1.H.2> LCO 3.4.1 RCS DNB parameters for pressurizer pressure, RCS average temperature, and RCS total flow rate shall be within the limits specified below:

<3.1.H.1.a> a. Pressurizer pressure ≥ [2200] psig; 2205

loop

<3.1.H.1.b> b. RCS average temperature ≤ [581] °F; and 571.5 PA.1

<3.1.H.2> c. RCS total flow rate ≥ [284,000] gpm. 375,600

<3.1.H.1> <3.1.H.2> APPLICABILITY: MODE 1.

<3.1.H.3>

---NOTE---

Pressurizer pressure limit does not apply during:

a. THERMAL POWER ramp > 5% RTP per minute; or

b. THERMAL POWER step > 10% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
<3.1.H.4> A. One or more RCS DNB parameters not within limits.	A.1 Restore RCS DNB parameter(s) to within limit.	2 hours
<3.1.H.5> <DOC L.1> <3.1.H.6> <DOC H.1> B. Required Action and associated Completion Time not met.	B.1 Be in MODE 2.	6 hours

SURVEILLANCE REQUIREMENTS

<CTS>	SURVEILLANCE		FREQUENCY
<Table 4.1-1, Item 7>	SR 3.4.1.1	Verify pressurizer pressure is ≥ ~~[2200]~~ 2205 psig.	12 hours
<Table 4.1-1, Item 4>	SR 3.4.1.2	Verify RCS average loop temperature is ≤ ~~[581]~~ 571.5 °F.	12 hours
<Table 4.1-1, Item 5>	SR 3.4.1.3	Verify RCS total flow rate is ≥ ~~[284,000]~~ 375,600 gpm.	12 hours
<4.3.B>	SR 3.4.1.4	----------NOTE---------- Not required to be performed until 24 hours after ≥ ~~[90]~~% RTP. ----------	
		Verify by precision heat balance that RCS total flow rate is ≥ ~~[284,000]~~ 375,600 gpm.	~~[18]~~ 24 months

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.1 RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits

BASES

BACKGROUND

These Bases address requirements for maintaining RCS pressure, temperature, and flow rate within limits assumed in the safety analyses. The safety analyses (Ref. 1) of normal operating conditions and anticipated operational occurrences assume initial conditions within the normal steady state envelope. The limits placed on RCS pressure, temperature, and flow rate ensure that the minimum departure from nucleate boiling ratio (DNBR) will be met for each of the transients analyzed.

The RCS pressure limit is consistent with operation within the nominal operational envelope. Pressurizer pressure indications are averaged to come up with a value for comparison to the limit. A lower pressure will cause the reactor core to approach DNB limits.

loop

The RCS coolant average temperature limit is consistent with full power operation within the nominal operational envelope. ~~Indications of temperature are averaged to determine a value for comparison to the limit.~~ A higher average temperature will cause the core to approach DNB limits. PA.1

Insert: B 3.4-1-01

The RCS flow rate normally remains constant during an operational fuel cycle with all pumps running. The minimum RCS flow limit corresponds to that assumed for DNB analyses. ~~Flow rate indications are averaged to come up with a value for comparison to the limit.~~ A lower RCS flow will cause the core to approach DNB limits.

Insert: B 3.4-1-02

Insert: B 3.4-1-c

Operation for significant periods of time outside these DNB limits increases the likelihood of a fuel cladding failure in a DNB limited event. DB.1

APPLICABLE SAFETY ANALYSES

The requirements of this LCO represent the initial conditions for DNB limited transients analyzed in the plant safety analyses (Ref. 1). The safety analyses have shown that transients initiated from the limits of this LCO will

(continued)

NUREG-1431 Markup Inserts
ITS SECTION 3.4.1 - RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits

INSERT: B 3.4-1-01

PA.1

RCS average temperature is determined by calculating the average temperature for each loop and then calculating the average of these average loop temperatures and this average of the averages is compared to the acceptance criteria.

INSERT: B 3.4-1-02

PA.1

RCS flow rate is determined by calculating the average flow rate for each loop and then calculating the sum of these average loop flow rates and this sum of the averages is compared to the acceptance criteria.

INSERT: B 3.4-1-03

DB.1

Calculations have shown that reactor heat equivalent to 10% rated power can be removed via the steam generators with natural circulation without violating DNBR limits. This analysis assumed conservative flow resistances including steam generator tube plugging and a locked rotor in each loop (Ref. 1).

BASES

APPLICABLE SAFETY ANALYSES (continued)

result in meeting the DNBR criterion of ≥ [1.3]. This is the acceptance limit for the RCS DNB parameters. Changes to the unit that could impact these parameters must be assessed for their impact on the DNBR criteria. The transients analyzed for include loss of coolant flow events and dropped or stuck rod events. A key assumption for the analysis of these events is that the core power distribution is within the limits of LCO 3.1.7, "Control Bank Insertion Limits"; LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)"; and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)."

6

T.1

2205

The pressurizer pressure limit of [2200] psig and the RCS average temperature limit of [581]°F correspond to analytical limits of [2205] psig and [595]°F used in the safety analyses, with allowance for measurement uncertainty.

and instrument error

includes the

Insert: B3.4-2-01

The RCS DNB parameters satisfy Criterion 2 of the NRC Policy Statement.

10 CFR 50.36

LCO

This LCO specifies limits on the monitored process variables—pressurizer pressure, RCS average temperature, and RCS total flow rate—to ensure the core operates within the limits assumed in the safety analyses. Operating within these limits will result in meeting the DNBR criterion in the event of a DNB limited transient.

loop

(i.e.,

Insert B3.4-2-02

RCS total flow rate contains a measurement error of [2.0]% based on performing a precision heat balance and using the result to calibrate the RCS flow rate indicators. Potential fouling of the feedwater venturi, which might not be detected, could bias the result from the precision heat balance in a nonconservative manner. Therefore, a penalty of [0.1]% for undetected fouling of the feedwater venturi raises the nominal flow measurement allowance to [2.1]% for no fouling.

Any fouling that might bias the flow rate measurement greater than [0.1]% can be detected by monitoring and trending various plant performance parameters. If detected, either the effect of the fouling shall be quantified and compensated for in the RCS flow rate measurement or the venturi shall be cleaned to eliminate the fouling.

PA.1

(continued)

DB.2

INSERT: B 3.4-2-01

The limit on RCS average loop temperature provides assurance that RCS temperatures are maintained within the normal steady state envelope of operation assumed in the safety analyses performed to support the Vantage + fuel reloads with asymmetric tube plugging among steam generators. A maximum full power Tcold of 547.7°F (including control deadband and measurement uncertainties) was assumed in these safety analyses. A Tavg of 578.3°F assures that a Tcold of 547.7°F is not exceeded at a measured flow of ≥ 375,600 gpm when considering asymmetric tube plugging among steam generators for DNB considerations. Therefore, the LCO limit of 571.5°F for RCS average loop temperature, which is based on meeting analysis assumptions for post-LOCA containment integrity, conservatively ensures that DNBR limits are met.

INSERT: B 3.4-2-02

The RCS total flow rate limit of 375,600 gpm allows a measurement uncertainty of 2.9% associated with the performance of Reactor Coolant System Flow Calculation.

BASES

LCO (continued)

~~The LCO numerical values for pressure, temperature, and flow rate are given for the measurement location but have not been adjusted for instrument error.~~

APPLICABILITY

In MODE 1, the limits on pressurizer pressure, RCS coolant average temperature, and RCS flow rate must be maintained during steady state operation in order to ensure DNBR criteria will be met in the event of an unplanned loss of forced coolant flow or other DNB limited transient. In all other MODES, the power level is low enough that DNB is not a concern.

A Note has been added to indicate the limit on pressurizer pressure is not applicable during short term operational transients such as a THERMAL POWER ramp increase > 5% RTP per minute or a THERMAL POWER step increase > 10% RTP. These conditions represent short term perturbations where actions to control pressure variations might be counterproductive. Also, since they represent transients initiated from power levels < 100% RTP, an increased DNBR margin exists to offset the temporary pressure variations.

Another set of limits on DNB related parameters is provided in SL 2.1.1, "Reactor Core SLs." Those limits are less restrictive than the limits of this LCO, but violation of a Safety Limit (SL) merits a stricter, more severe Required Action. Should a violation of this LCO occur, the operator must check whether or not an SL may have been exceeded.

ACTIONS

A.1

loop

RCS pressure and RCS average temperature are controllable and measurable parameters. With one or both of these parameters not within LCO limits, action must be taken to restore parameter(s).

RCS total flow rate is not a controllable parameter and is not expected to vary during steady state operation. If the indicated RCS total flow rate is below the LCO limit, power must be reduced, as required by Required Action B.1, to restore DNB margin and eliminate the potential for violation of the accident analysis bounds.

(continued)

BASES

ACTIONS

A.1 (continued)

The 2 hour Completion Time for restoration of the parameters provides sufficient time to adjust plant parameters, to determine the cause for the off normal condition, and to restore the readings within limits, and is based on plant operating experience.

B.1

If Required Action A.1 is not met 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 2 within 6 hours. In MODE 2, the reduced power condition eliminates the potential for violation of the accident analysis bounds. The Completion Time of 6 hours is reasonable to reach the required plant conditions in an orderly manner.

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1

Since Required Action A.1 allows a Completion Time of 2 hours to restore parameters that are not within limits, the 12 hour Surveillance Frequency for pressurizer pressure is sufficient to ensure the pressure can be restored to a normal operation, steady state condition following load changes and other expected transient operations. The 12 hour interval has been shown by operating practice to be sufficient to regularly assess for potential degradation and to verify operation is within safety analysis assumptions.

Insert: B3.4-4-01

SR 3.4.1.2

loop

Since Required Action A.1 allows a Completion Time of 2 hours to restore parameters that are not within limits, the 12 hour Surveillance Frequency for RCS average temperature is sufficient to ensure the temperature can be restored to a normal operation, steady state condition

(continued)

INSERT: B 3.4-4-01

Pressurizer pressure indications are averaged to determine the value for comparison to the LCO limit.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.1.2 (continued)

following load changes and other expected transient operations. The 12 hour interval has been shown by operating practice to be sufficient to regularly assess for potential degradation and to verify operation is within safety analysis assumptions.

Insert: B3.4-5-01

SR 3.4.1.3

The 12 hour Surveillance Frequency for RCS total flow rate is performed using the installed flow instrumentation. The 12 hour interval has been shown by operating practice to be sufficient to regularly assess potential degradation and to verify operation within safety analysis assumptions.

SR 3.4.1.4

Insert: B3.4-5-02

Measurement of RCS total flow rate by performance of a precision calorimetric heat balance once every ~~[18]~~ 24 months allows the installed RCS flow instrumentation to be calibrated and verifies the actual RCS flow rate is greater than or equal to the minimum required RCS flow rate.

The Frequency of ~~[18]~~ 24 months reflects the importance of verifying flow after a refueling outage when the core has been altered, which may have caused an alteration of flow resistance.

SG Tubes plugged or other activities performed,

This SR is modified by a Note that allows entry into MODE 1, without having performed the SR, and placement of the unit in the best condition for performing the SR. The Note states that the SR is not required to be performed until 24 hours after ≥ ~~[90%]~~ RTP. This exception is appropriate since the heat balance requires the plant to be at a minimum of ~~[90%]~~ RTP to obtain the stated RCS flow accuracies. The Surveillance shall be performed within 24 hours after reaching ~~[90%]~~ RTP.

REFERENCES

1. FSAR, Section ~~[15]~~ 14.

INSERT: B 3.4-5-01

RCS average loop temperature is determined by calculating the average temperature for each loop and then calculating the average of these average loop temperatures and this average of the averages is compared to the acceptance criteria.

INSERT: B 3.4-5-02

verifies that the actual RCS flow rate is greater than or equal to the minimum required RCS flow rate.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.1:

"RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits"

PART 6:

Justification of Differences between

NUREG-1431 and IP3 ITS

JUSTIFICATION OF DIFFERENCES FROM NUREG-1431
ITS SECTION 3.4.1 - RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits

RETENTION OF EXISTING REQUIREMENT (CURRENT LICENSING BASIS)

None

PLANT-SPECIFIC WORDING PREFERENCE OR MINOR EDITORIAL IMPROVEMENT

PA.1 Corrected typographical error or made a minor editorial improvement to improve clarity and ensure requirements are fully understood and consistently applied. There are no technical changes to requirements as specified in NUREG 1431, Rev. 1; therefore, this change is not a significant or generic deviation from NUREG 1431, Rev 1.

PLANT-SPECIFIC DIFFERENCE IN THE DESIGN OR DESIGN BASIS

DB.1 Design or implementation details are incorporated or revised as necessary to more precisely describe IP3 current design or practice. These changes are intended to describe the design, improve clarity, or ensure requirements are fully understood and consistently applied. Unless identified and described blow, these changes are self-explanatory. A detailed description of the design, accident analysis assumptions, and Operability requirements are incorporated into the IP3 ITS Bases. These changes maintain the IP3 current licensing basis except as identified and justified in the CTS/ITS discussion of changes.

DB.2 An IP3 specific description of the LCO requirements and applicable safety analysis for this LCO was approved by Amendment 170 dated 10/22/96. This information is incorporated into the ITS Bases.

DIFFERENCE BASED ON A GENERIC CHANGE TRAVELER FOR NUREG-1431

T.1 This change incorporates Generic Change TSTF-136, Rev.0 (WOG-59) which revises the numbering of cross references to other ITS Specifications because ITS LCO 3.1.1 and ITS LCO 3.1.2 were combined.

DIFFERENCE FOR ANY REASON OTHER THAN ABOVE

None

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.2:
"RCS Minimum Temperature for Criticality"

PART 1:

Indian Point 3
Improved Technical Specifications and Bases

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.2 RCS Minimum Temperature for Criticality

LCO 3.4.2 Each RCS loop average temperature (T_{avg}) shall be ≥ 540°F.

APPLICABILITY: MODE 1,
MODE 2 with k_{eff} ≥ 1.0.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. T_{avg} in one or more RCS loops not within limit.	A.1 Be in MODE 2 with k_{ef} < 1.0.	30 minutes

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.4.2.1 Verify RCS T_{avg} in each loop ≥ 540°F.	-----NOTE------ Only required if T_{avg} - T_{ref} deviation, and low T_{avg} alarm not reset and any RCS loop T_{avg} < 547°F ---------- 30 minutes thereafter

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.2 RCS Minimum Temperature for Criticality

BASES

BACKGROUND

This LCO is based upon meeting several major considerations before the reactor can be made critical and while the reactor is critical.

The first consideration is moderator temperature coefficient (MTC), LCO 3.1.3, "Moderator Temperature Coefficient (MTC)." In the transient and accident analyses, the MTC is assumed to be negative (except during physics testing) and the operating temperature is assumed to be within the nominal operating envelope while the reactor is critical. The LCO on minimum temperature for criticality helps ensure the plant is operated consistent with these assumptions.

The second consideration is the protective instrumentation. Because certain protective instrumentation (e.g., excore neutron detectors) can be affected by moderator temperature, a temperature value within the nominal operating envelope is chosen to ensure proper indication and response while the reactor is critical.

The third consideration is the pressurizer operating characteristics. The transient and accident analyses assume that the pressurizer is within its normal startup and operating range (i.e., saturated conditions and steam bubble present). It is also assumed that the RCS temperature is within its normal expected range for startup and power operation. Since the density of the water, and hence the response of the pressurizer to transients, depends upon the initial temperature of the moderator, a minimum value for moderator temperature within the nominal operating envelope is chosen.

The fourth consideration is that the reactor vessel is above its minimum nil ductility reference temperature when the reactor is critical.

BASES

APPLICABLE SAFETY ANALYSES

Although the RCS minimum temperature for criticality is not itself an initial condition assumed in Design Basis Accidents (DBAs), the closely aligned temperature for hot zero power (HZP) is a process variable that is an initial condition of DBAs, such as the rod cluster control assembly (RCCA) withdrawal, RCCA ejection, and main steam line break accidents performed at zero power that either assumes the failure of, or presents a challenge to, the integrity of a fission product barrier.

All low power safety analyses assume initial RCS loop temperatures ≥ the HZP temperature of 547°F (Ref. 1). The minimum temperature for criticality limitation provides a small band, 7°F, for critical operation below HZP. This band allows critical operation below HZP during plant startup and does not adversely affect any safety analyses since the MTC is not significantly affected by the small temperature difference between HZP and the minimum temperature for criticality.

The RCS minimum temperature for criticality satisfies Criterion 2 of 10 CFR 50.36.

LCO

Compliance with the LCO ensures that the reactor will not be made or maintained critical ($k_{eff} \geq 1.0$) at a temperature less than a small band below the HZP temperature, which is assumed in the safety analysis. Failure to meet the requirements of this LCO may produce initial conditions inconsistent with the initial conditions assumed in the safety analysis.

APPLICABILITY

In MODE 1 and MODE 2 with $k_{eff} \geq 1.0$, LCO 3.4.2 is applicable since the reactor can only be critical ($k_{eff} \geq 1.0$) in these MODES.

The special test exception of LCO 3.1.8, "MODE 2 PHYSICS TESTS Exceptions," permits PHYSICS TESTS to be performed at ≤ 5% RTP with RCS loop average temperatures slightly lower than normally allowed so that fundamental nuclear characteristics of the core

BASES

APPLICABILITY (continued)

can be verified. In order for nuclear characteristics to be accurately measured, it may be necessary to operate outside the normal restrictions of this LCO. For example, to measure the MTC at beginning of cycle, it is necessary to allow RCS loop average temperatures to fall below $T_{no\ load}$, which may cause RCS loop average temperatures to fall below the temperature limit of this LCO.

ACTIONS

A.1

If the parameters that are outside the limit cannot be restored, 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 MODE 2 with $k_{eff} < 1.0$ within 30 minutes. Rapid reactor shutdown can be readily and practically achieved within a 30 minute period. The allowed time is reasonable, based on operating experience, to reach MODE 2 $k_{eff} < 1.0$ in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1

RCS loop average temperature is required to be verified at or above 540°F every 30 minutes when T_{avg}-T_{ref} deviation, and low T_{avg} alarm is not reset and any RCS loop T_{avg} < 547°F.

The Note modifies the SR. When any RCS loop average temperature is < 547°F and the T_{avg} - T_{ref} deviation, and low T_{avg} alarm are alarming, RCS loop average temperatures could fall below the LCO requirement without additional warning. The SR to verify RCS loop average temperatures every 30 minutes is frequent enough to prevent the inadvertent violation of the LCO.

BASES

REFERENCES 1. FSAR, Section 14.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.2:
"RCS Minimum Temperature for Criticality"

PART 2:

CURRENT TECHNICAL SPECIFICATION PAGES

Annotated to show differences between CTS and ITS

CTS pages and associated TSCRs annotated for this ITS Specification :

CTS Page No.	Effective Amendment	Annotated Amendment	TSCR No.	TSCR Description	ITS Status of TSCR
3.1-25	149	149	No TSCRs	No TSCRs for this Page	N/A
T 4.1-1(1)	170 TSCR 98-043	170 TSCR 98-043	IPN 98-043	Instrument Channel Surveillance Intervals Extended to 24 Months	Incorporated

A.1 A.2

SEE ITS 3.1.8

C. MINIMUM CONDITIONS FOR CRITICALITY

SEE ITS 3.1.3

1. Except during low power physics test, the reactor shall not be made critical at any temperature above which the moderator temperature coefficient is positive.

~~2. This section intentionally deleted.~~ Mode 1, Mode 2 with keff ≥ 1.0 — A.1

LCO 3.4.2

Req. Act A.1

3. ~~At all times during critical operation~~ the lowest loop T_{avg} shall be no lower than 540 °F. — L.1

a. If T_{avg} is less than 540°F when the reactor is critical, restore T_{avg} to ≥ 540 °F within 15 minutes or be in hot shutdown within the following 15 minutes. — Mode 2 with keff < 1.0; 30 — A.3

SEE ITS 3.4.9

4. The reactor shall be maintained subcritical by at least 1% $\frac{\Delta k}{k}$ until normal water level is established in the pressurizer.

Basis

During the early part of the initial fuel cycle, the moderator temperature coefficient is calculated to be slightly positive at coolant temperatures below the power operating range. [1] [2] The moderator coefficient at low temperatures will be most positive at the beginning of life of the fuel cycle, when the boron concentration in the coolant is the greatest. Later in the life of the fuel cycle, the boron concentration in the coolant will be lower and the moderator coefficient will be either less positive or will be negative. At all times, the moderator coefficient is negative in the power operating range. [1] [2] Suitable physics measurements of moderator coefficient of reactivity will be made as part of the startup program to verify analytic predictions. — A.1

The requirement that the reactor is not to be made critical when the moderator coefficient is positive has been imposed to prevent any unexpected power excursion during normal operations as a result of an increase in moderator temperature. This requirement is waived during low power physics tests to permit measurement of reactor moderator coefficient and other physics design parameters of interest. During physics tests, special operating precautions will be taken.

The requirement that the reactor is not to be made critical except when T_{avg} is ≥ 540 °F provides assurance that an overpressure event will not occur whenever the reactor vessel is in the nil-ductility temperature range and that the reactor is operated within the bounds of the safety analyses. The safety analyses, which assume a critical temperature of 547 °F, are applicable for critical temperatures as low as 540 °F. Heatup to this temperature will be accomplished by operating the reactor coolant pumps. The Surveillance requirement to support this specification is provided in Table 4.1-1 item no. 4.

The requirement for bubble formation in the pressurizer when the reactor has passed the threshold of 1% subcriticality will assure that the reactor coolant not be solid when criticality is achieved.

References:

1. FSAR Table 3.2-1

2. FSAR Figure 3.2-9

TABLE 4.1-1 (Sheet 1 of 6)

MINIMUM FREQUENCIES FOR CHECKS, CALIBRATIONS AND TESTS OF INSTRUMENT CHANNELS

Channel Description	Check	Calibrate	Test	Remarks
1. Nuclear Power Range	S	D (1) M (3)*	Q (2)** Q (4)	1) Heat balance calibration 2) Bistable action (permissive, rod stop, trips) 3) Upper and lower chambers for axial offset 4) Signal to Δ T
2. Nuclear Intermediate Range	S (1)	N.A.	P (2)	1) Once/shift when in service 2) Verification of channel response to simulated inputs
3. Nuclear Source Range	S (1)	N.A.	P (2)	1) Once/shift when in service 2) Verification of channel response to simulated inputs
4. Reactor Coolant Temperature	S ## (2)	24M	Q (1)	1) Overtemperature ΔT, overpower ΔT, and low T_{avg} 2) Normal instrument check interval is once/shift T_{avg} instrument check interval reduced to every 30 minutes when: - T_{avg}-T_{ref} deviation and low T_{avg} alarms are not reset and, Control banks are above 0 steps
		Any RCS Loop T_{avg} < 547		L.2
		Mode 1, Mode 2 with $k_{eff} \geq 1.0$		L.3
5. Reactor Coolant Flow	S ##	24M	Q	
6. Pressurizer Water Level	S	18M	Q	
7. Pressurizer Pressure	S ##	24M	Q	High and Low

SR 3.4.2.1

Amendment No. 38, 65, 74, 93, 107, 125, 126, 137, 140, 149, 150, 158, 170

ITS 3.4.2

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.2:
"RCS Minimum Temperature for Criticality"

PART 3:

DISCUSSION OF CHANGES

Differences between CTS and ITS

DISCUSSION OF CHANGES
ITS SECTION 3.4.2 - RCS Minimum Temperature for Criticality

ADMINISTRATIVE

A.1 In the conversion of the Indian Point Un3 Current Technical Specifications (CTS) to the plant specific Improved Technical Specifications (ITS) certain wording preferences or conventions are adopted which do not result in technical changes (either actual or interpretational). Additionally, editorial changes, reformatting, and revised numbering are adopted to make ITS consistent with the conventions in NUREG-1431, Standard Technical Specifications, Westinghouse Plants, Rev. 1, i.e., the improved Standard Technical Specifications.

The CTS Bases are deleted and replaced with comprehensive ITS Bases designed to support interpretation and implementation of the associated Technical Specifications. The Bases explain, clarify, and document the reasons (i.e., bases) for the associated Technical Specifications, and reflect the IP3 plant specific design, analyses, and licensing basis. In accordance with 10 CFR 50.36(a), the ITS Bases are included with the proposed ITS conversion application; however, deletion of the CTS Bases and the adoption of the ITS Bases is an administrative change with no impact on safety.

A.2 CTS Limiting Conditions for Operation (LCOs) and Surveillance Requirements (SRs) include statements of the objective and the applicability. The CTS statements of objective and applicability are deleted because these statements do not establish any requirements and do not provide any guidance for the application of CTS requirements. Therefore, deletion of these statements has no significant adverse impact on safety.

A.3 CTS 3.1.C.3.a requires restoring Tavg to ≥ 540°F within 15 minutes or being in hot shutdown (Mode 3) within the following 15 minutes whenever Tavg is not within required limits. Under the same conditions, ITS LCO 3.4.2, Required Action A.1, requires being in Mode 2 with Keff < 1.0 (See ITS 3.4.2, DOC L.1) within 30 minutes. Although the CTS appear to allocate 15 minutes for a restoration attempt before initiating the shutdown, the CTS and ITS completion times are functionally equivalent. Therefore, this is an administrative change with no impact on safety.

DISCUSSION OF CHANGES
ITS SECTION 3.4.2 - RCS Minimum Temperature for Criticality

MORE RESTRICTIVE

None

LESS RESTRICTIVE

L.1 CTS 3.1.C.3.a requires that the plant be placed in hot shutdown (Mode 3) if Tavg cannot be maintained above the minimum limit for critical operation of 540°F.

Under the same conditions, ITS 3.4.2, Required Action A.1 (as modified by TSTF-26 (WOG-13)), requires that the plant be in Mode 2 with Keff <1.0. The difference is that CTS 3.1.C.3.a requires that the reactor be shutdown by ≥ 1.3% Δk/k (in accordance with CTS definition of hot shutdown) when Tavg cannot be maintained above the required minimum; whereas, ITS 3.4.2 requires only that Keff is <1.0.

This change is needed because both CTS and ITS require Tavg above the required minimum only when the reactor is critical. However, when requirements are not met, CTS requires Actions after the reactor is outside the LCO Applicability. This change is acceptable because in Mode 2 with Keff < 1.0 the plant is outside the Applicability of LCO 3.4.2. The LCO Applicability is established for Mode 1 and Mode 2 with keff ≥ 1.0 because moderator temperature affects the moderator temperature reactivity coefficient that must be maintained within assumed values only when the reactor is critical. This change is consistent with NUREG-1431, Generic Change TSTF-26 (WOG-13), which revises LCO 3.4.2, RCS Minimum Temperature for Criticality, Required Action A.1, to require entering Mode 2 with Keff < 1.0 to be consistent with the LCO Applicability. This change does not have a significant adverse impact on safety.

L.2 CTS Table 4.1-1, Item 4, and ITS SR 3.4.2.1 both require verification that RCS loop average temperature is ≥ 540°F every 30 minutes if the Tavg-Tref deviation and low Tavg alarm is not reset (i.e., alarming). However, CTS requires this verification any time the alarm is not reset; whereas, ITS SR 3.4.2.1 requires this verification only if any RCS loop average temperature is < 547°F (i.e., within 7°F of the LCO limit).

This change is needed because the Tavg-Tref deviation alarm and low Tavg alarm will actuate significantly above the 540°F LCO limit when power level is high. Therefore, a formal requirement to verify RCS loop average temperature ≥ 540°F every 30 minutes is an administrative burden with no commensurate safety benefit. This change is acceptable because the ITS SR 3.4.2.1 requirement to initiate increased monitoring when RCS loop average temperature is < 547°F (i.e., 7°F above the LCO limit) provides substantial margin before the violation of the LCO limit even if there is a period of time when the alarm is already alarming but accelerated monitoring is not required. This change does not have a significant adverse impact on safety.

L.3 CTS Table 4.1-1, Item 4, and ITS SR 3.4.2.1 both require verification RCS loop average temperature is ≥ 540°F every 30 minutes when Tavg-Tref deviation and the low Tavg alarm are not reset (i.e., alarming). CTS requires this verification any time the control banks are above step zero that will occur before entering the CTS LCO applicability (i.e., reactor critical). ITS SR 3.4.2.1 requires the verification only when keff ≥ 1.0 consistent with the applicability requirements for the ITS LCO. This change is acceptable because reactor criticality (i.e., LCO applicability) is a readily identifiable condition; therefore, ITS SR 3.4.2.1 will be performed whenever the LCO is applicable. This change does not have a significant adverse impact on safety.

REMOVED DETAIL

None

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.2:
"RCS Minimum Temperature for Criticality"

PART 4:

No Significant Hazards Considerations
for
Changes between CTS and ITS
that are
Less Restrictive

No Significant Hazard Considerations for Changes that are Administrative, More Restrictive, and Removed Details are the same for all Packages. A Copy is included at the end of the Package.

NO SIGNIFICANT HAZARDS EVALUATION
ITS SECTION 3.4.2 - RCS Minimum Temperature for Criticality

LESS RESTRICTIVE
("L.1" Labeled Comments/Discussions)

New York Power Authority has evaluated the proposed Technical Specification change identified as "Less Restrictive" in accordance with the criteria set forth in 10 CFR 50.92, and has determined that the proposed change does not involve a significant hazards consideration. The bases for the determination that the proposed changes do not involve a significant hazards consideration are discussed below.

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

   CTS 3.1.C.3.a requires that the plant be placed in hot shutdown (Mode 3) if Tavg cannot be maintained above the minimum limit for critical operation of 540°F. Under the same conditions, ITS 3.4.2, Required Action A.1 (as modified by TSTF-26 (WOG-13)), requires that the plant be in Mode 2 with Keff <1.0. The difference is that CTS 3.1.C.3.a requires establishing shutdown margin ≥ 1.3% Δk/k (in accordance with CTS definition of hot shutdown) when Tavg cannot be maintained above the required minimum whereas ITS 3.4.2 requires only that Keff <1.0.

   This change will not result in a significant increase in the probability of an accident previously evaluated because the minimum temperature for criticality is not the initiator of any analyzed event; therefore, the proposed change to the actions when this limit is not met is not the initiator of any analyzed event. This change will not result in a significant increase in the consequences of an accident previously evaluated because in Mode 2 with Keff < 1.0 the plant is outside the Applicability of LCO 3.4.2. The LCO Applicability is established for Mode 1 and Mode 2 with 2 with keff ≥ 1.0 because moderator temperature affects the moderator temperature reactivity coefficient which must be maintained within assumed values only when the reactor is critical. This change is consistent with NUREG-1431, Generic Change TSTF-26 (WOG-13), which revises LCO 3.4.2, RCS Minimum Temperature for Criticality, Required Action A.1, to require entering Mode 2 with Keff < 1.0 to be consistent with the LCO Applicability.

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

   The proposed changes will not involve any physical changes to plant systems, structures, or components (SSC). The changes in normal Plant operation are consistent with the current safety analysis assumptions because both the CTS and ITS establish a requirement for minimum temperature for criticality only when the reactor is critical. Therefore, these changes will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   This change does not involve a significant reduction in a margin of safety because the proposed action places the plant outside the applicability when minimum temperature for criticality cannot be met and both the CTS and ITS establish requirement for minimum temperature for criticality only when the reactor is critical.

LESS RESTRICTIVE
("L.2" Labeled Comments/Discussions)

New York Power Authority has evaluated the proposed Technical Specification change identified as "Less Restrictive" in accordance with the criteria set forth in 10 CFR 50.92, and has determined that the proposed change does not involve a significant hazards consideration. The bases for the determination that the proposed changes do not involve a significant hazards consideration are discussed below.

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

   This change relaxes requirements for accelerated monitoring of RCS loop average temperature when Tavg-Tref deviation and the low Tavg alarm is alarming so that accelerated monitoring is required only if any RCS loop average temperature is < 547°F (i.e., 7°F above the LCO limit). This

change will not result in a significant increase in the probability or consequences of an accident previously evaluated because the ITS SR 3.4.2.1 requirement to initiate increased monitoring when RCS loop average temperature is < 547°F (i.e., 7°F above the LCO limit) provides substantial margin before any potential violation of the LCO limit even if there is a period of time when the alarm is alarming but accelerated monitoring is not required.

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

   The proposed changes will not involve any physical changes to plant systems, structures, or components (SSC). The changes in normal Plant operation are consistent with the current safety analysis assumptions because there is no change to the method used to monitor temperature. Therefore, these changes will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   This change does not involve a significant reduction in a margin of safety because the ITS SR 3.4.2.1 requirement to initiate increased monitoring when RCS loop average temperature is < 547°F (i.e., 7°F above the LCO limit) provides substantial margin before any potential violation of the LCO limit even if there is a period of time when the alarm is already alarming but accelerated monitoring is not required.

LESS RESTRICTIVE
("L.3" Labeled Comments/Discussions)

New York Power Authority has evaluated the proposed Technical Specification change identified as "Less Restrictive" in accordance with the criteria set forth in 10 CFR 50.92, and has determined that the proposed change does not involve a significant hazards consideration. The bases for the determination that the proposed changes do not involve a significant hazards consideration are discussed below.

NO SIGNIFICANT HAZARDS EVALUATION
ITS SECTION 3.4.2 - RCS Minimum Temperature for Criticality

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

   CTS Table 4.1-1, Item 4, and ITS SR 3.4.2.1 both require verification RCS loop average temperature is ≥ 540°F every 30 minutes when Tavg-Tref deviation and the low Tavg alarm is not reset. CTS requires this verification any time the control banks are above step zero which occurs prior to entering the CTS LCO applicability (reactor critical). ITS SR 3.4.2.1 requires the verification only when keff ≥ 1.0 consistent with the applicability requirements for the ITS LCO. This change will not result in a significant increase in the probability or consequences of an accident previously evaluated because reactor criticality (i.e., LCO applicability) is a readily identifiable condition; therefore, there is no change to the level of assurance that ITS SR 3.4.2.1 will be performed whenever the LCO is applicable.

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

   The proposed changes will not involve any physical changes to plant systems, structures, or components (SSC). The changes in normal Plant operation are consistent with the current safety analysis assumptions because minimum temperature for criticality will still be verified using the existing methodology. Therefore, these changes will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   This change does not involve a significant reduction in a margin of safety because reactor criticality (i.e., LCO applicability) is a readily identifiable condition; therefore, there is no change to the level of assurance that ITS SR 3.4.2.1 will be performed whenever the LCO is applicable.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.2:
"RCS Minimum Temperature for Criticality"

PART 5:

NUREG-1431
Annotated to show differences between
NUREG-1431 and ITS

Status of NUREG 1431 Generic Changes for ITS 3.4.2

This ITS Specification is based on NUREG-1431 Specification No. **3.4.2**
as modified by the following Generic Changes:

OG No.	TSTF No.	Generic Change Description	NRC STATUS	IP3 STATUS	JD No.
WOG-004.4	**012 R0**	DELETE LCO 3.1.9 AND 3.1.11 (PHYSICS TESTS EXCEPTIONS)	See Next Rev.	N/A	**N/A**
WOG-013	**026 R0**	REVISE THE ACTION FOR MINIMUM TEMPERATURE FOR CRITICALITY TO MATCH THE APPLICABILITY	Approved by NRC	Incorporated	**T.1**
WOG-014	**027 R2**	REVISE SR FREQUENCY FOR MINIMUM TEMPERATURE FOR CRITICALITY	NRC Rejects: TSTF to Revise	Not Incorporated	**N/A**
WOG-059	**136 R0**	COMBINE LCO 3.1.1 AND 3.1.2	Approved by NRC	Incorporated (Re-number cross reference only)	**N/A**

<CTS> 3.4 REACTOR COOLANT SYSTEM (RCS)

<3.1.C> 3.4.2 RCS Minimum Temperature for Criticality

<3.1.C.3> LCO 3.4.2 Each RCS loop average temperature (T_{avg}) shall be ≥ ~~541~~ 540 °F.

<3.1.C.3> APPLICABILITY: MODE 1,
MODE 2 with k_{eff} ≥ 1.0.

ACTIONS

	CONDITION	REQUIRED ACTION	COMPLETION TIME
<3.1.C.3.a> <DOC A.3> <DOC L.1>	A. T_{avg} in one or more RCS loops not within limit.	A.1 Be in MODE ~~3~~ 2 with Keff < 1.0	30 minutes T.1

SURVEILLANCE REQUIREMENTS

<CTS>

<Table 4.1-1, Item 4, Note 2>

<DOC L.2>

<DOC L.3>

SURVEILLANCE	FREQUENCY
SR 3.4.2.1 Verify RCS T_{avg} in each loop ≥ [541] (540) °F.	-----NOTE------ Only required if [T_{avg} - T_{ref} deviation, ~~low~~ (and) low T_{avg}] alarm not reset and any RCS loop T_{avg} < [547] °F (DB.1) ---------- 30 minutes thereafter

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.2 RCS Minimum Temperature for Criticality

BASES

BACKGROUND

This LCO is based upon meeting several major considerations before the reactor can be made critical and while the reactor is critical.

The first consideration is moderator temperature coefficient (MTC), LCO 3.1.~~4~~3, "Moderator Temperature Coefficient (MTC)." In the transient and accident analyses, the MTC is assumed to be ~~in a range from slightly positive to~~ negative (except during physics testing), and the operating temperature is assumed to be within the nominal operating envelope while the reactor is critical. The LCO on minimum temperature for criticality helps ensure the plant is operated consistent with these assumptions.

The second consideration is the protective instrumentation. Because certain protective instrumentation (e.g., excore neutron detectors) can be affected by moderator temperature, a temperature value within the nominal operating envelope is chosen to ensure proper indication and response while the reactor is critical.

The third consideration is the pressurizer operating characteristics. The transient and accident analyses assume that the pressurizer is within its normal startup and operating range (i.e., saturated conditions and steam bubble present). It is also assumed that the RCS temperature is within its normal expected range for startup and power operation. Since the density of the water, and hence the response of the pressurizer to transients, depends upon the initial temperature of the moderator, a minimum value for moderator temperature within the nominal operating envelope is chosen.

The fourth consideration is that the reactor vessel is above its minimum nil ductility reference temperature when the reactor is critical.

APPLICABLE SAFETY ANALYSES

Although the RCS minimum temperature for criticality is not itself an initial condition assumed in Design Basis Accidents (DBAs), the closely aligned temperature for hot

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

zero power (HZP) is a process variable that is an initial condition of DBAs, such as the rod cluster control assembly (RCCA) withdrawal, RCCA ejection, and main steam line break accidents performed at zero power that either assumes the failure of, or presents a challenge to, the integrity of a fission product barrier.

All low power safety analyses assume initial RCS loop temperatures ≥ the HZP temperature of 547°F (Ref. 1). The minimum temperature for criticality limitation provides a small band, 6°F, for critical operation below HZP. This band allows critical operation below HZP during plant startup and does not adversely affect any safety analyses since the MTC is not significantly affected by the small temperature difference between HZP and the minimum temperature for criticality.

The RCS minimum temperature for criticality satisfies Criterion 2 of the NRC Policy Statement.

LCO

Compliance with the LCO ensures that the reactor will not be made or maintained critical ($k_{eff} \geq 1.0$) at a temperature less than a small band below the HZP temperature, which is assumed in the safety analysis. Failure to meet the requirements of this LCO may produce initial conditions inconsistent with the initial conditions assumed in the safety analysis.

APPLICABILITY

In MODE 1 and MODE 2 with $k_{eff} \geq 1.0$, LCO 3.4.2 is applicable since the reactor can only be critical ($k_{eff} \geq 1.0$) in these MODES.

The special test exception of LCO 3.1.10, "MODE 2 PHYSICS TESTS Exceptions," permits PHYSICS TESTS to be performed at ≤ 5% RTP with RCS loop average temperatures slightly lower than normally allowed so that fundamental nuclear characteristics of the core can be verified. In order for nuclear characteristics to be accurately measured, it may be necessary to operate outside the normal restrictions of this LCO. For example, to measure the MTC at beginning of cycle, it is necessary to allow RCS loop average temperatures to fall below $T_{no\ load}$, which may cause RCS loop average

(continued)

BASES

APPLICABILITY (continued)

temperatures to fall below the temperature limit of this LCO.

ACTIONS

A.1

If the parameters that are outside the limit cannot be restored, 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 MODE 3 within 30 minutes. Rapid reactor shutdown can be readily and practically achieved within a 30 minute period. The allowed time is reasonable, based on operating experience, to reach MODE 3 in an orderly manner and without challenging plant systems.

2 with keff <1.0

T.1

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1

RCS loop average temperature is required to be verified at or above [541] °F every 30 minutes when ~~[~~T_{avg}-T_{ref} deviation, ~~low~~ low T_{avg} ~~]~~ alarm not reset and any RCS loop T_{avg} < ~~[~~547~~]~~ °F.

540

and

The Note modifies the SR. When any RCS loop average temperature is < ~~[~~547~~]~~ °F and the ~~[~~T_{avg} - T_{ref} deviation, ~~low~~ low T_{avg} ~~]~~ alarm is alarming, RCS loop average temperatures could fall below the LCO requirement without additional warning. The SR to verify RCS loop average temperatures every 30 minutes is frequent enough to prevent the inadvertent violation of the LCO.

are

and the

REFERENCES

1. FSAR, Section [15.0.3].

14

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.2:
"RCS Minimum Temperature for Criticality"

PART 6:

Justification of Differences between

NUREG-1431 and IP3 ITS

JUSTIFICATION OF DIFFERENCES FROM NUREG-1431
ITS SECTION 3.4.2 - RCS Minimum Temperature for Criticality

RETENTION OF EXISTING REQUIREMENT (CURRENT LICENSING BASIS)

None

PLANT-SPECIFIC WORDING PREFERENCE OR MINOR EDITORIAL IMPROVEMENT

PA.1 Corrected typographical error or made a minor editorial improvement to improve clarity and ensure requirements are fully understood and consistently applied. There are no technical changes to requirements as specified in NUREG 1431, Rev. 1; therefore, this change is not a significant or generic deviation from NUREG 1431, Rev 1.

PLANT-SPECIFIC DIFFERENCE IN THE DESIGN OR DESIGN BASIS

DB.1 Design or implementation details are incorporated or revised as necessary to more precisely describe IP3 current design or practice. These changes are intended to describe the design, improve clarity, or ensure requirements are fully understood and consistently applied. Unless identified and described blow, these changes are self-explanatory. A detailed description of the design, accident analysis assumptions, and Operability requirements are incorporated into the IP3 ITS Bases. These changes maintain the IP3 current licensing basis except as identified and justified in the CTS/ITS discussion of changes.

DIFFERENCE BASED ON A GENERIC CHANGE TRAVELER FOR NUREG-1431

T.1 This change incorporates Generic Change TSTF-26, Rev.0 (WOG-13) which revises the Required Action to place the reactor outside the Applicable Mode so that it is consistent with the LCO Applicability for Minimum Temperature for Criticality. This generic change to NUREG 1431, Rev. 1, has been approved by the NRC.

DIFFERENCE FOR ANY REASON OTHER THAN ABOVE

None

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.3:
"RCS Pressure and Temperature (P/T) Limits"

PART 1:

Indian Point 3
Improved Technical Specifications and Bases

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.3 RCS Pressure and Temperature (P/T) Limits

LCO 3.4.3 RCS pressure, RCS temperature, and RCS heatup and cooldown rates shall be maintained within the limits specified in the PTLR.

APPLICABILITY: At all times.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. ---------NOTE--------- Required Action A.2 shall be completed whenever this Condition is entered. ---------- Requirements of LCO not met in MODE 1, 2, 3, or 4.	A.1	Restore parameter(s) to within limits.	30 minutes
	AND		
	A.2	Determine RCS is acceptable for continued operation.	72 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1	Be in MODE 3.	6 hours
	AND		
	B.2	Be in MODE 5.	36 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. ---------NOTE--------- Required Action C.2 shall be completed whenever this Condition is entered. ---------- Requirements of LCO not met any time in other than MODE 1, 2, 3, or 4.	C.1 Initiate action to restore parameter(s) to within limits.	Immediately
	AND	
	C.2 Determine RCS is acceptable for continued operation.	Prior to entering MODE 4

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.3.1	----------NOTE---------- Only required to be performed during RCS heatup and cooldown operations and RCS inservice leak and hydrostatic testing. ---------- Verify RCS pressure, RCS temperature, and RCS heatup and cooldown rates are within the limits specified in the PTLR.	30 minutes

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.3 RCS Pressure and Temperature (P/T) Limits

BASES

BACKGROUND

All components of the RCS are designed to withstand effects of cyclic loads due to system pressure and temperature changes. These loads are introduced by startup (heatup) and shutdown (cooldown) operations, power transients, and reactor trips. This LCO limits the pressure and temperature changes during RCS heatup and cooldown, within the design assumptions and the stress limits for cyclic operation.

The Pressure and Temperature Limits Report (PTLR) contains P/T limit curves for heatup, cooldown, inservice leak and hydrostatic (ISLH) testing, and data for the maximum rate of change of reactor coolant temperature (Ref. 1).

Each P/T limit curve defines an acceptable region for normal operation. The usual use of the curves is operational guidance during heatup or cooldown maneuvering, when pressure and temperature indications are monitored and compared to the applicable curve to determine that operation is within the allowable region.

The LCO establishes operating limits that provide a margin to brittle failure of the reactor vessel and piping of the reactor coolant pressure boundary (RCPB). The vessel is the component most subject to brittle failure, and the LCO limits apply mainly to the vessel. The limits do not apply to the pressurizer, which has different design characteristics and operating functions.

10 CFR 50, Appendix G (Ref. 2), requires the establishment of P/T limits for specific material fracture toughness requirements of the RCPB materials. Reference 2 requires an adequate margin to brittle failure during normal operation, anticipated operational occurrences, and system hydrostatic tests. It mandates the use of the American Society of Mechanical Engineers (ASME) Code, Section III, Appendix G (Ref. 3).

BASES

BACKGROUND (Continued)

The neutron embrittlement effect on the material toughness is reflected by increasing the nil ductility reference temperature (RT_{NDT}) as exposure to neutron fluence increases.

The actual shift in the RT_{NDT} of the vessel material will be established periodically by removing and evaluating the irradiated reactor vessel material specimens, in accordance with ASTM E 185 (Ref. 4) and Appendix H of 10 CFR 50 (Ref. 5). The operating P/T limit curves will be adjusted, as necessary, based on the evaluation findings and the recommendations of Regulatory Guide 1.99 (Ref. 6).

The P/T limit curves are composite curves established by superimposing limits derived from stress analyses of those portions of the reactor vessel and head that are the most restrictive. At any specific pressure, temperature, and temperature rate of change, one location within the reactor vessel will dictate the most restrictive limit. Across the span of the P/T limit curves, different locations are more restrictive, and, thus, the curves are composites of the most restrictive regions.

The heatup curve represents a different set of restrictions than the cooldown curve because the directions of the thermal gradients through the vessel wall are reversed. The thermal gradient reversal alters the location of the tensile stress between the outer and inner walls.

The criticality limit curve includes the Reference 2 requirement that it be ≥ 40°F above the heatup curve or the cooldown curve, and not less than the minimum permissible temperature for ISLH testing. However, the criticality curve is not operationally limiting; a more restrictive limit exists in LCO 3.4.2, "RCS Minimum Temperature for Criticality."

The consequence of violating the LCO limits is that the RCS has been operated under conditions that can result in brittle failure of the RCPB, possibly leading to a nonisolable leak or loss of coolant accident. In the event these limits are exceeded, an

BASES

BACKGROUND (continued)

evaluation must be performed to determine the effect on the structural integrity of the RCPB components. The ASME Code, Section XI, Appendix E (Ref. 7), provides a recommended methodology for evaluating an operating event that causes an excursion outside the limits.

APPLICABLE SAFETY ANALYSES

The P/T limits are not derived from Design Basis Accident (DBA) analyses. They are prescribed during normal operation to avoid encountering pressure, temperature, and temperature rate of change conditions that might cause undetected flaws to propagate and cause nonductile failure of the RCPB, an unanalyzed condition. Reference 1 establishes the methodology for determining the P/T limits. Although the P/T limits are not derived from any DBA, the P/T limits are acceptance limits since they preclude operation in an unanalyzed condition.

RCS P/T limits satisfy Criterion 2 of 10 CFR 50.36.

LCO

The two elements of this LCO are:

a. The limit curves for heatup, cooldown, and ISLH testing; and

b. Limits on the rate of change of temperature.

The LCO limits apply to all components of the RCS pressure boundary, except the pressurizer. These limits define allowable operating regions and permit a large number of operating cycles while providing a wide margin to nonductile failure.

The limits for the rate of change of temperature control the thermal gradient through the vessel wall and are used as inputs for calculating the heatup, cooldown, and ISLH testing P/T limit curves. Thus, the LCO for the rate of change of temperature restricts stresses caused by thermal gradients and also ensures

BASES

LCO (continued)

the validity of the P/T limit curves. Heatup and cooldown limits are specified in hourly increments (i.e., the heatup and cooldown limits are based on the temperature change averaged over a one hour period).

Violating the LCO limits places the reactor vessel outside of the bounds of the stress analyses and can increase stresses in other RCPB components. The consequences depend on several factors, as follows:

a. The severity of the departure from the allowable operating P/T regime or the severity of the rate of change of temperature;

b. The length of time the limits were violated (longer violations allow the temperature gradient in the thick vessel walls to become more pronounced); and

c. The existences, sizes, and orientations of flaws in the vessel material.

APPLICABILITY

The RCS P/T limits LCO provides a definition of acceptable operation for prevention of nonductile failure in accordance with 10 CFR 50, Appendix G (Ref. 2). Although the P/T limits were developed to provide guidance for operation during heatup or cooldown (MODES 3, 4, and 5) or ISLH testing, their Applicability is at all times in keeping with the concern for nonductile failure. The limits do not apply to the pressurizer.

During MODES 1 and 2, other Technical Specifications provide limits for operation that can be more restrictive than or can supplement these P/T limits. LCO 3.4.1, "RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits"; LCO 3.4.2, "RCS Minimum Temperature for Criticality"; and Safety Limit 2.1, "Safety Limits," also provide operational restrictions for pressure and temperature and maximum pressure. Furthermore, MODES 1 and 2 are above the temperature range of concern for nonductile failure, and stress analyses have been

BASES

APPLICABILITY (continued)

performed for normal maneuvering profiles, such as power ascension or descent.

ACTIONS

A.1 and A.2

Operation outside the P/T limits during MODE 1, 2, 3, or 4 must be corrected so that the RCPB is returned to a condition that has been verified by stress analyses.

The 30 minute Completion Time reflects the urgency of restoring the parameters to within the analyzed range. Most violations will not be severe, and the activity can be accomplished in this time in a controlled manner.

Besides restoring operation within limits, an evaluation is required to determine if RCS operation can continue. The evaluation must verify the RCPB integrity remains acceptable and must be completed before continuing operation. Several methods may be used, including comparison with pre-analyzed transients in the stress analyses, new analyses, or inspection of the components.

ASME Code, Section XI, Appendix E (Ref. 7), may be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline.

The 72 hour Completion Time is reasonable to accomplish the evaluation. The evaluation for a mild violation is possible within this time, but more severe violations may require special, event specific stress analyses or inspections. A favorable evaluation must be completed before continuing to operate.

Condition A is modified by a Note requiring Required Action A.2 to be completed whenever the Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the excursion outside the allowable limits. Restoration alone per Required Action A.1 is insufficient because higher than analyzed stresses may have occurred and may have affected the RCPB integrity.

BASES

ACTIONS

B.1 and B.2

If a Required Action and associated Completion Time of Condition A are not met, the plant must be placed in a lower MODE because either the RCS remained in an unacceptable P/T region for an extended period of increased stress or a sufficiently severe event caused entry into an unacceptable region. Either possibility indicates a need for more careful examination of the event, best accomplished with the RCS at reduced pressure and temperature. In reduced pressure and temperature conditions, the possibility of propagation with undetected flaws is decreased.

If the required restoration activity cannot be accomplished within 30 minutes, Required Action B.1 and Required Action B.2 must be implemented to reduce pressure and temperature.

If the required evaluation for continued operation cannot be accomplished within 72 hours or the results are indeterminate or unfavorable, action must proceed to reduce pressure and temperature as specified in Required Action B.1 and Required Action B.2. A favorable evaluation must be completed and documented before returning to operating pressure and temperature conditions.

Pressure and temperature are reduced by bringing the plant to MODE 3 within 6 hours and to MODE 5 with RCS pressure significantly reduced and limited by LCO 3.4.12, Low Temperature Overpressure Protection (LTOP), 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.

C.1 and C.2

Actions must be initiated immediately to correct operation outside of the P/T limits at times other than when in MODE 1, 2, 3, or 4, so that the RCPB is returned to a condition that has been verified by stress analysis.

BASES

ACTIONS

C.1 and C.2 (continued)

The immediate Completion Time reflects the urgency of initiating action to restore the parameters to within the analyzed range. Most violations will not be severe, and the activity can be accomplished in this time in a controlled manner.

Besides restoring operation within limits, an evaluation is required to determine if RCS operation can continue. The evaluation must verify that the RCPB integrity remains acceptable and must be completed prior to entry into MODE 4. Several methods may be used, including comparison with pre-analyzed transients in the stress analyses, or inspection of the components.

ASME Code, Section XI, Appendix E (Ref. 7), may be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline.

Condition C is modified by a Note requiring Required Action C.2 to be completed whenever the Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the excursion outside the allowable limits. Restoration alone per Required Action C.1 is insufficient because higher than analyzed stresses may have occurred and may have affected the RCPB integrity.

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1

Verification that operation is within the PTLR limits is required every 30 minutes when RCS pressure and temperature conditions are undergoing planned changes. This Frequency is considered reasonable in view of the control room indication available to monitor RCS status. Heatup and cooldown limits are specified in hourly increments (i.e., the heatup and cooldown limits are based on the temperature change averaged over a one hour period). Also,

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1 (continued)

since temperature rate of change limits are specified in hourly increments, 30 minutes permits assessment and correction for minor deviations within a reasonable time.

Surveillance for heatup, cooldown, or ISLH testing may be discontinued when the definition given in the relevant plant procedure for ending the activity is satisfied.

This SR is modified by a Note that only requires this SR to be performed during system heatup, cooldown, and ISLH testing. No SR is given for criticality operations because LCO 3.4.2 contains a more restrictive requirement.

REFERENCES

1. WCAP-7924-A, July 1972.

2. 10 CFR 50, Appendix G.

3. ASME, Boiler and Pressure Vessel Code, Section III, Appendix G.

4. ASTM E 185-70.

5. 10 CFR 50, Appendix H.

6. Regulatory Guide 1.99, Revision 2, May 1988.

7. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix E.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.3:
"RCS Pressure and Temperature (P/T) Limits"

PART 2:

CURRENT TECHNICAL SPECIFICATION PAGES

Annotated to show differences between CTS and ITS

CTS pages and associated TSCRs annotated for this ITS Specification :

CTS Page No.	Effective Amendment	Annotated Amendment	TSCR No.	TSCR Description	ITS Status of TSCR
3.1-17	179	179	No TSCRs	No TSCRs for this Page	N/A
3.1-18	179	179	No TSCRs	No TSCRs for this Page	N/A
3.1-19	121	121	No TSCRs	No TSCRs for this Page	N/A
3.1-20	121	121	No TSCRs	No TSCRs for this Page	N/A
3.1-21	121	121	No TSCRs	No TSCRs for this Page	N/A
3.1-22	121	121	No TSCRs	No TSCRs for this Page	N/A
3.1-23(F 3.1-1)	179	179	No TSCRs	No TSCRs for this Page	N/A
3.1-24(F 3.1-2)	179	179	No TSCRs	No TSCRs for this Page	N/A
4.3-1	179	179	No TSCRs	No TSCRs for this Page	N/A
4.3-2	179	179	No TSCRs	No TSCRs for this Page	N/A
4.3-3	179	179	No TSCRs	No TSCRs for this Page	N/A

3.4.3 RCS Pressure and Temp limits

Add LCO 3.4.3 Applicability

A.1 A.2

A.3

B. HEATUP AND COOLDOWN

Specifications

SEE RELOCATED

A.5

1. The reactor coolant temperature and pressure and system heatup and cooldown rates averaged over one hour (with the exception of the pressurizer) shall be limited in accordance with Figure 3.1-1 and Figure 3.1-2 for the service period up to 13.3 effective full-power years (EFPYs). The heatup and cooldown rates shall not exceed 60°F/hr and 100°F/hr respectively. LA.1

within limits in PTLR

a. Allowable combinations of pressure and temperature for specific temperature change rates are below and to the right of the limit lines shown. Limit lines for cooldown rates between those presented may be obtained by interpolation. LA.1

2. The limit lines shown in Figure 3.1-1 and Figure 3.1-2 shall be recalculated periodically using methods discussed in the Basis and results of surveillance specimens as covered in Specification 4.2. The order of specimen removal may be modified based on the results of testing of previously removed specimens. LA.1

SEE RELOCATED CTS

3. The secondary side of the steam generator shall not be pressurized above 200 psig if the temperature of the steam generator is below 70°F.

4. The pressurizer heatup and cooldown rates averaged over one hour shall not exceed 100°F/hr and 200°F/hr, respectively. The spray shall not be used if the temperature difference between the pressurizer and the spray fluid is greater than 320°F.

5. Reactor Coolant System integrity tests shall be performed in accordance with Section 4.3. A.4

Basis

Fracture Toughness Properties A.1

The fracture toughness properties of the ferritic materials in the reactor vessel are determined in accordance with the Summer 1968 Section III of the ASME Boiler and Pressure Vessel Code [6] and ASTM E185 [5] and in accordance with additional reactor vessel requirements. These properties are then evaluated in accordance with Appendix G of the 1972 Summer Addenda to Section III of the ASME Boiler and Pressure Vessel Code [1], and the calculation methods described in WCAP-7924 [2].

Add LCO 3.4.3, Conditions A, B & C and associated Req. Act. M.1

M.2

Add SR 3.4.3.1

The first reactor vessel material surveillance capsule was removed during the 1978 refueling outage. This capsule has been tested by Westinghouse Corporation and the results have been evaluated and reported [illegible]. Similar reports were prepared for the surveillance capsules [illegible] removed in 1982 and 1987. Based on the Westinghouse evaluation, heatup and cooldown curves (Figures 3.1-1 and 3.1-2) were developed for up to 13.3 EFPYs of reactor operation.

Generic Letter 88-11 requested that licensees use the methodology of Regulatory Guide 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials", to predict the effect of neutron radiation on reactor vessel materials as required by paragraph V.A. of 10 CFR part 50, Appendix G. Capsule Z was analyzed [4] and new pressure-temperature curves were developed using this methodology.

The maximum value in RT_{NDT} after 13.3 EFPYs of operation is projected to be 214°F at the 1/4 T and 172°F at the 3/4 T vessel wall locations for Plate B2803-3 the controlling plate. Plate B2803-3 was also the controlling plate for the operating period up to 11 EFPYs.

Heatup and cooldown limit curves are calculated using the most limiting value of RT_{NDT} at the end of 13.3 years of service life. The 13.3 year service life period is chosen such that the limiting RT_{NDT} at the 1/4 T location in the core region is higher than the RT_{NDT} of the limiting unirradiated material. This service period assures that all components in the Reactor Coolant System will be operated conservatively in accordance with Code recommendations.

The highest RT_{NDT} of the core region material is determined by adding the radiation induced ΔRT_{NDT} for the applicable time period to the original RT_{NDT} shown in Table Q4.2-1 [3].

A.1

A.1

Heatup and Cooldown Curves

Allowable pressure-temperature relationships for various heatup and cooldown rates are calculated using methods derived from Non Mandatory Appendix G in Section III of the ASME Boiler and Pressure Vessel Code and discussed in detail in WCAP-7924. [2]

The approach specifies that the allowable total stress intensity factor (K_I) at any time during heatup or cooldown cannot be greater than that shown on the K_{IR} curve [1] for the metal temperature at that time. Furthermore, the approach applies an explicit safety factor of 2.0 on the stress intensity factor induced by pressure gradients. Thus, the governing equation for the heatup-cooldown analysis is:

$$2\,K_{Im} + K_{It} \leq K_{IR} \qquad (1)$$

where:

K_{Im} is the stress intensity factor caused by membrane (pressure) stress

K_{It} is the stress intensity factor caused by the thermal gradients

K_{IR} is provided by the code as a function of temperature relative to the RT_{NDT} of the material.

During the heatup analysis, Equation (1) is evaluated for two distinct situations.

First, allowable pressure-temperature relationships are developed for steady state (i.e., zero rate of change of temperature) conditions assuming the presence of the code reference 1/4 T deep flaw at the ID of the pressure vessel. Due to the fact that, during heatup, the thermal gradients in the vessel wall tend to produce compressive stresses at the 1/4 T locations, the tensile stresses induced by internal pressure are somewhat alleviated. Thus, a pressure-temperature curve based on steady state conditions (i.e., no thermal stresses) represents a lower bound of all similar curves for finite heatup rates when the 1/4 T location is treated as the governing factor.

The second portion of the heatup analysis concerns the calculation of pressure temperature limitations for the case in which the 3/4 T location becomes the controlling factor. Unlike the situation at the 1/4 T location, at the 3/4 T position (i.e., the tip of the 1/4 T deep O.D. flaw) the thermal gradients established during heatup produce stresses which are tensile in nature; and, thus, tend to reinforce the pressure stresses present. These thermal stresses are, of course, dependent on both the rate of heatup and the time (or water temperature) along the heatup ramp. Furthermore, since the thermal stresses at 3/4 T are tensile and increase with increasing heatup rate, a lower bound curve similar to that described in the preceding paragraph cannot be defined. Rather, each heatup rate of interest must be analyzed on an individual basis.

A.1

Following the generation of pressure-temperature curves for both the steady state and finite heatup rate situations, the final limit curves are produced in the following fashion. First, a composite curve is constructed based on a point by point comparison of the steady state and finite heatup rate data. At any given temperature, the allowable pressure is taken to be the lesser of the two values taken from the curves under consideration. The composite curve is then adjusted to allow for possible errors in the pressure and temperature sensing instruments.

The use of the composite curve becomes mandatory in setting heatup limitations because it is possible for conditions to exist such that over the course of the heatup ramp the controlling analysis switches from the O.D. to the I.D. location; and the pressure limit must, at all times, be based on the most conservative case.

The cooldown analysis proceeds in the same fashion as that for heatup, with the exception that the controlling location is always at 1/4 T. The thermal gradients induced during cooldown tend to produce tensile stresses at the 1/4 T location and compressive stresses at the 3/4 T position. Thus, the ID flaw is clearly the worst case.

As in the case of heatup, allowable pressure temperature relations are generated for both steady state and finite cooldown rate situations. Composite limit curves are then constructed for each cooldown rate of interest. Again adjustments are made to account for pressure and temperature instrumentation error.

The use of the composite curve in the cooldown analysis is necessary because system control is based on a measurement of reactor coolant temperature, whereas the limiting pressure is calculated using the material temperature at the tip of the assumed reference flaw. During cooldown, the 1/4 T vessel location is at a higher temperature than the fluid adjacent to the vessel I.D. This condition is, of course, not true for the steady-state situation. It follows that the ΔT induced during cooldown results in a calculated higher allowable K_{IR} for finite cooldown rates than for steady state under certain conditions.

Because operation control is on coolant temperature, and cooldown rate may vary during the cooldown transient, the limit curves shown in Figure 3.1-2 represent a composite curve consisting of the more conservative values calculated for steady state and the specific cooling rate shown.

Details of these calculations are provided in WCAP-7924 [2]. Information on the specific calculations used to develop the current heatup-cooldown curves can be found in Reference 9.

A.1

~~**Pressurizer Limits**~~

~~Although the pressurizer operates at temperature ranges above those for which there is reason for concern about brittle fracture, operating limits are provided to assure compatibility of operation with the fatigue analysis performed in accordance with the ASME Boiler and Pressure Vessel Code, Section III, 1965 Edition and associated Code Addenda through the Summer 1966 Addendum.~~

A.1

REFERENCES

1. ASME Boiler and Pressure Vessel Code, Section III, 1972 Summer Addenda.

2. WCAP-7924, "Basis for Heatup and Cooldown Limit Curves", W. S. Hazelton, S. L. Anderson, S. E. Yanichko, July 1972.

3. FSAR Volume 5, Response to Question Q4.2.

4. Intentionally deleted.

5. ASTM E185-70, Surveillance Tests on Structural Materials in Nuclear Reactors.

6. ASME Boiler and Pressure Vessel Code, Section III, Summer 1965.

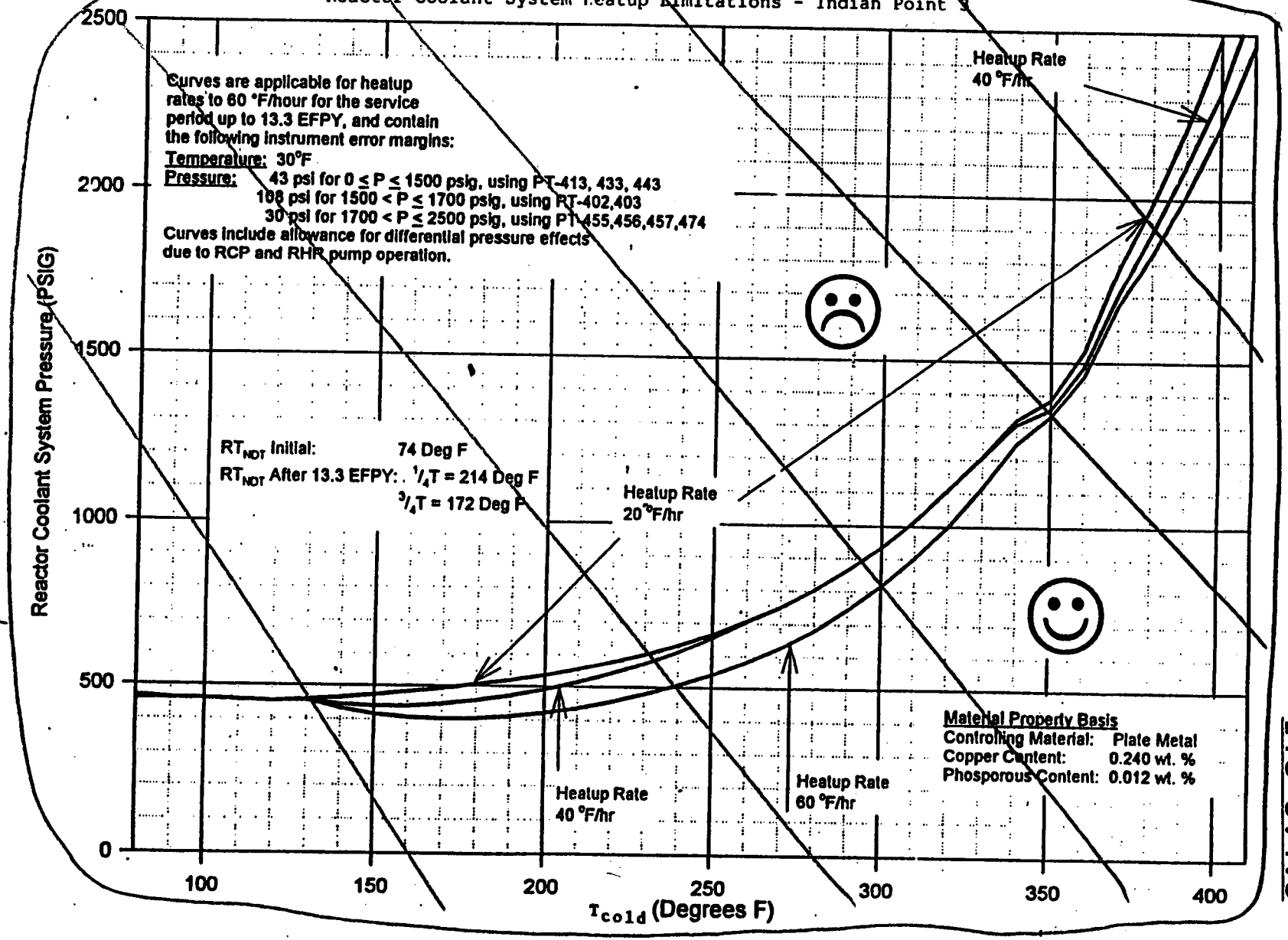
7. WCAP-9491, "Analysis of Capsule T from the Indian Point Unit No. 3 Reactor Vessel Radiation Surveillance Program", J. A. Davidson, S. L. Anderson, W. T. Kaiser, April 1979.

8. WCAP-11815, "Analysis of Capsule Z from the New York Power Authority Indian Point Unit 3 Reactor Vessel Radiation Surveillance Program," S. E. Yanichko, S. L. Anderson, L. Albertin, March 1988.

9. "Indian Point Unit 3 Final Report on Appendix G Reactor Vessel Pressure - Temperature Limits", ABB Combustion Engineering, July 24, 1990.

10. WCAP-10300-1, Analysis of Capsule Y from the Power Authority of the State of New York Indian Point Unit 3 Reactor Vessel Radiation Surveillance Program, S.E. Yanichko, S.L. Anderson, March 1983.

FIGURE 3.1-1
Reactor Coolant System Heatup Limitations - Indian Point 3

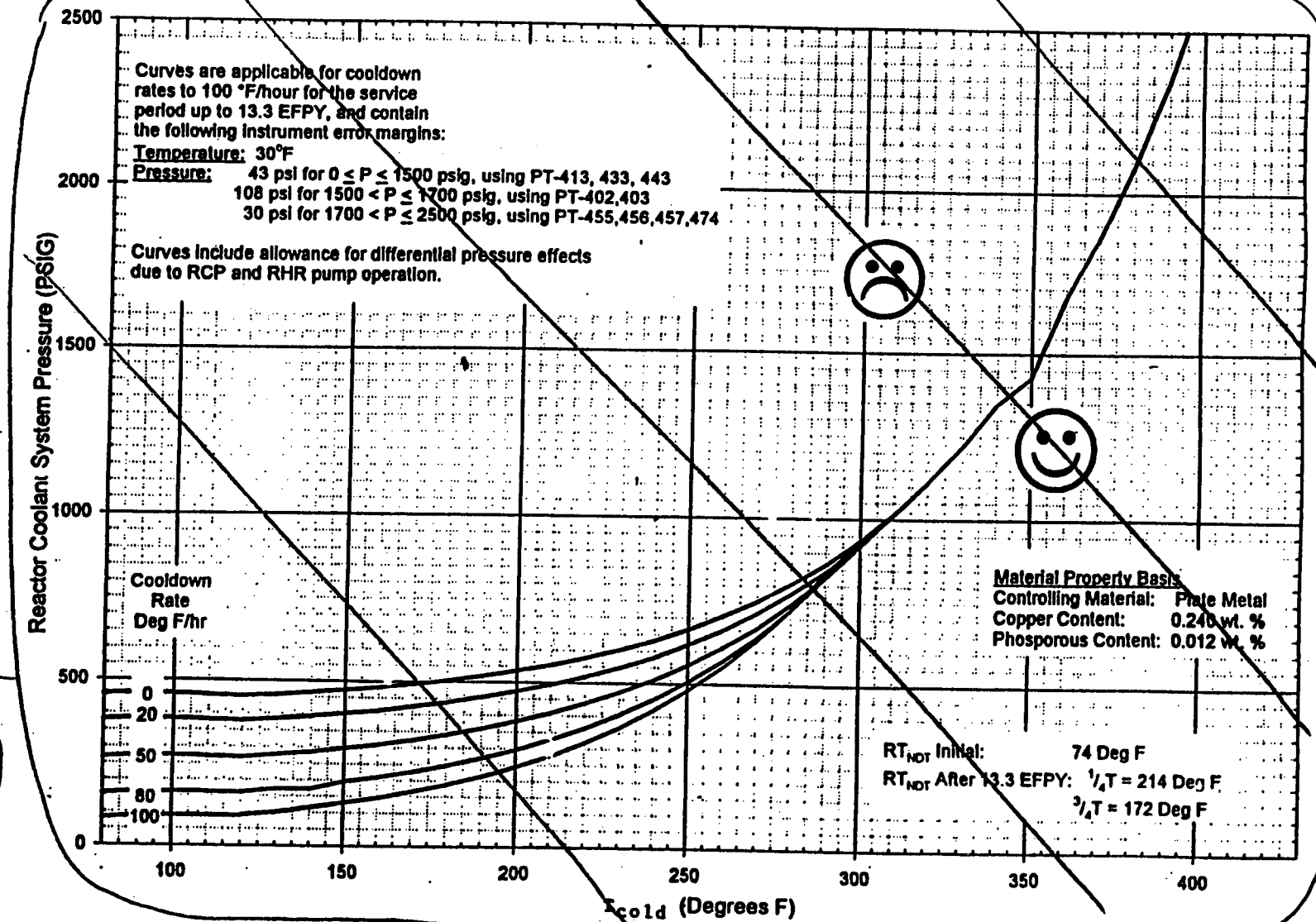


LA.1

ITS 3.4.3

FIGURE 3.1-2

Reactor Coolant System Cooldown Limitations - Indian Point 3



LA.1

4.3 REACTOR COOLANT SYSTEM (RCS) TESTING

A. Reactor Coolant System Integrity Testing

A.2

Applicability

Applies to test requirements for Reactor Coolant System integrity.

Objective

To specify tests for Reactor Coolant System integrity after the system is closed following refueling, repair, replacement or modification.

Specification

SEE RELOCATED CTS

a) The Reactor Coolant System shall be tested for leakage at normal operating pressure prior to plant startup following each refueling outage, in accordance with the requirements of ASME Section XI.

b) Testing of repairs, replacements or modifications for the Reactor Coolant System shall meet the requirements of ASME Section XI.

LCO 3.4.3

~~c)~~ The Reactor Coolant System leak test temperature-pressure relationship shall be in accordance with the limits of Figure 4.3-1 for heatup for the first 13.3 EFPYs of operations. Figure 4.3-1 will be recalculated periodically. Allowable pressures during cooldown from the leak test temperature shall be in accordance with Figure 3.1-2.

PTLR

LA.1

Basis

Leak test of the Reactor Coolant System is required by the ASME Boiler and Pressure Vessel Code, Section XI, to ensure leak tightness of the system during operation. The test frequency and conditions are specified in the Code.

For repairs on components, the thorough non-destructive testing gives a very high degree of confidence in the integrity of the system, and will detect any significant defects in and near the new welds. In all cases, the leak test will assure leak tightness during normal operation.

The inservice leak test temperatures are shown on Figure 4.3-1. The temperatures are calculated in accordance with ASME Code Section III, Appendix G. This Code requires that a safety factor of 1.5 times the stress intensity factor caused by pressure be applied to the calculation.

A.1

Amendment No. 28, 101, 109, 121, 170, 171, 179

For the first 13.3 effective full power years, it is predicted that the highest RT_{NDT} in the core region taken at the 1/4 thickness will be 214°F. The temperature determined by methods of ASME Code Section III for 1989 psig is 134°F above this RT_{NDT} and for 2485 psig (maximum) is 153°F above this RT_{NDT}. The minimum inservice leak test temperature requirements for periods up to 13.3 effective full power years are shown on Figure 4.3-1.

The heatup limits specified on the heatup curve, Figure 4.3-1, must not be exceeded while the reactor coolant system is being heated to the inservice leak test temperature. For cooldown from the leak test temperature, the limitations of Figure 3.1-2 must not be exceeded. Figures 4.3-1 and 3.1-2 are recalculated periodically, using methods discussed in the Basis for Specification 3.1.B and results of surveillance specimens, as covered in Specification 4.2.

Reference

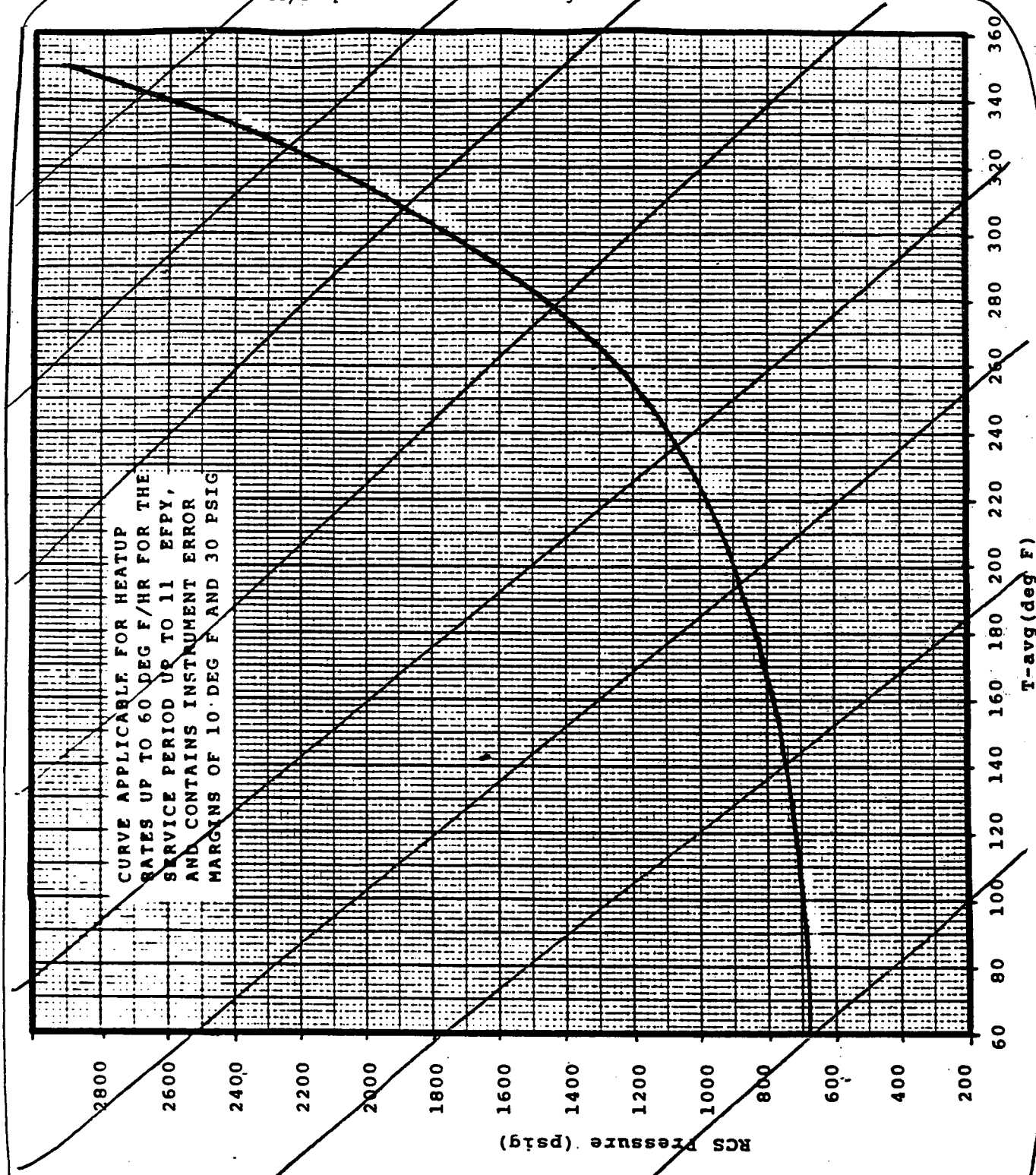
1. FSAR, Section 4.

2. "Indian Point Unit 3 Final Report on Appendix G Reactor Vessel Pressure-Temperature Limits" ABB-Combustion Engineering, July 24, 1990

A.1

LA.1

FIGURE 4.3-1
Pressure/Temperature Limits for Hydrostatic Leak Test



MATERIAL PROPERTY BASIS

Controlling Material:	Plate Metal	RT_{NDT} INITIAL:	74°F
Copper Content:	0.24 wt. %	RT_{NDT} AFTER 11 EFPY:	1/4 T = 202°F
Phosphorous Content:	0.012 wt. %		3/4 T = 163°F

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.3:
"RCS Pressure and Temperature (P/T) Limits"

PART 3:

DISCUSSION OF CHANGES

Differences between CTS and ITS

DISCUSSION OF CHANGES
ITS SECTION 3.4.3 - RCS Pressure and Temperature (P/T) Limits

ADMINISTRATIVE

A.1 In the conversion of the Indian Point Unit 3 Current Technical Specifications (CTS) to the plant specific Improved Technical Specifications (ITS) certain wording preferences or conventions are adopted which do not result in technical changes (either actual or interpretational). Additionally, editorial changes, reformatting, and revised numbering are adopted to make ITS consistent with the conventions in NUREG-1431, Standard Technical Specifications, Westinghouse Plants, Rev. 1, i.e., the improved Standard Technical Specifications.

The CTS Bases are deleted and replaced with comprehensive ITS Bases designed to support interpretation and implementation of the associated Technical Specifications. The Bases explain, clarify, and document the reasons (i.e., bases) for the associated Technical Specifications, and reflect the IP3 plant specific design, analyses, and licensing basis. In accordance with 10 CFR 50.36(a), the ITS Bases are included with the proposed ITS conversion application; however, deletion of the CTS Bases and the adoption of the ITS Bases is an administrative change with no impact on safety.

A.2 CTS Limiting Conditions for Operation (LCOs) and Surveillance Requirements (SRs) include statements of the objective and the applicability. The CTS statements of objective and applicability are deleted because these statements do not establish any requirements and do not provide any guidance for the application of CTS requirements. Therefore, deletion of these statements has no significant adverse impact on safety.

A.3 CTS 3.1.B, Heatup and Cooldown, establishes requirements for reactor coolant system temperature and pressure and system heatup and cooldown rate limits, but does not specify when the requirements are applicable. ITS LCO 3.4.3, Applicability, makes an explicit statement that reactor coolant system temperature and pressure and system heatup and cooldown rate limits are applicable at all times because violation could damage the pressure vessel for future use even if there is no fuel in the

vessel. This is an administrative change with no impact on safety because the ITS LCO 3.4.3, Applicability, is consistent with a reasonable interpretation of the existing requirements.

A.4 CTS 3.1.B.5 specifies that reactor coolant system integrity tests are performed in accordance with Section 4.3. This statement is deleted because the organization and format of the ITS eliminate the need for cross references. This is an administrative change with no impact on safety.

A.5 CTS 3.1.B.1 includes the clarification that heatup and cooldown rates are "averaged over one hour" to ensure proper application of the heatup and cooldown limits. Although this clarification is not included as part of ITS LCO 3.4.3, the Bases for ITS SR 3.4.3.1 include the same clarification (i.e., the ITS Bases specify that heatup and cooldown limits are based on the change during an hour period). This is an administrative change with no impact on safety.

MORE RESTRICTIVE

M.1 CTS 3.1.B. Heatup and Cooldown, establishes requirements for reactor coolant system temperature and pressure and RCS system heatup and cooldown rate limits; however, CTS 3.1.B does not specify required actions if these limits are not met. ITS LCO 3.4.3, Conditions A, B and C and associated Required Actions, establish specific requirements and completion times for restoration of pressure and temperature limits and for subsequent determinations that the RCS is acceptable for continued operation after any of these limits are violated. These more restrictive requirements for actions following the violation of a pressure or temperature limits or a heatup or cooldown limits are acceptable because they do not introduce any operation that is un-analyzed while requiring a more conservative response than is currently required for the restoration of pressure and temperature limits and follow-up verification that continued operation is acceptable. Therefore, this change has no adverse impact on safety.

M.2 CTS 3.1.B, Heatup and Cooldown, does not specify any required surveillances for the periodic or systematic verification that RCS pressure and temperature and RCS heatup and cooldown rates are within the specified limits. ITS SR 3.4.3.1 is added to require verification that operation is within the PTLR limits (See ITS 3.4.3, DOC LA.1) every 30 minutes when RCS pressure and temperature conditions are undergoing planned changes and during inservice leak and hydrostatic testing.

ITS SR 3.4.3.1 is modified by a Note that requires this SR to be performed only during system heatup, cooldown, and leak testing. Periodic verification that RCS pressure and temperature limits are met is not required in Modes 1 and 2 because LCO 3.4.2 contains a more restrictive requirements for pressure and temperature.

During those periods when ITS SR 3.4.3.1 must be performed, a Frequency of once per 30 minutes is specified because heatup and cooldown limits are specified in hourly increments (i.e., the heatup and cooldown limits are based on the change during an hour period and is consistent with CTS requirements). Therefore, formal verification at 30 minute intervals permits assessment and correction for minor deviations within a reasonable time.

These more restrictive changes are acceptable because they do not introduce any operation that is un-analyzed while requiring a more conservative response than is currently required for the verification that pressure-temperature limits are met. Therefore, this change has no adverse impact on safety.

LESS RESTRICTIVE

None

REMOVED DETAIL

LA.1 CTS 3.1.B, Heatup and Cooldown, and CTS 4.3, RCS Integrity Testing, include information such as the following:

a. specific limits for reactor coolant temperature and pressure and system heatup and cooldown rates in Figure 3.1-1 and Figure 3.1-2;

b. pressure temperature limits during leak tests in Figure 4.3-1; an allowance that interpolation of pressure-temperature curves is permitted;

c. the stipulation that specified values for heatup and cooldown rates are the maximum permitted values at any time;

d. the information that Figures 3.1-1 and 3.1-2 are valid up to 11.00 effective full-power years;

e. the information that limits must be periodically recalculated;

f. the clarification that heatup and cooldown rates are based on the average temperature over a one hour period; and,

g. requirements for vessel specimen removal.

These details, including CTS Figures 3.1-1 and 3.1-2, are not retained in the ITS and are relocated to the Pressure Temperature Limits Report (PTLR) in accordance with the guidance provided in Generic Letter 96-03. This change is needed because pressure temperature limits being moved to the PTLR are revised on a periodic basis and currently requires Technical Specification changes.

This change is acceptable because ITS LCO 3.4.3 maintains the requirement to meet these pressure and temperature limits and ITS 5.6.6, Reactor Coolant System (RCS) Pressure and Temperature Limits Report (PTLR), maintains detailed requirements for the establishment of these pressure and temperature limits including a requirement to use analytical methods previously reviewed and approved by the NRC and a requirement to provide a copy of the PTLR to the NRC upon issuance for each reactor vessel fluence period and for any revision or supplement thereto.

This change is a less restrictive administrative change with no impact on safety because no requirements are being deleted from Technical Specifications and an appropriate change control process and an appropriate level of regulatory oversight are maintained for the information being relocated out of the Technical Specifications.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.3:
"RCS Pressure and Temperature (P/T) Limits"

PART 4:

No Significant Hazards Considerations
for
Changes between CTS and ITS
that are
Less Restrictive

No Significant Hazard Considerations for Changes that are Administrative, More Restrictive, and Removed Details are the same for all Packages. A Copy is included at the end of the Package.

NO SIGNIFICANT HAZARDS EVALUATION
ITS SECTION 3.4.3 - RCS Pressure and Temperature (P/T) Limits

LESS RESTRICTIVE
("L.1" Labeled Comments/Discussions)

There are no less restrictive changes for the adoption of this ITS.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.3:
"RCS Pressure and Temperature (P/T) Limits"

PART 5:

NUREG-1431
Annotated to show differences between
NUREG-1431 and ITS

Status of NUREG 1431 Generic Changes for ITS 3.4.3

This ITS Specification is based on NUREG-1431 Specification No. **3.4.3**
as modified by the following Generic Changes:

OG No.	TSTF No.	Generic Change Description	NRC STATUS	IP3 STATUS	JD No.
N/A	**N/A**	NO GENERIC CHANGES ARE POSTED AGAINST THIS SPECIFICATION.	Not Applicable	Not Applicable	**N/A**

<CTS>

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.3 RCS Pressure and Temperature (P/T) Limits

<3.1.B.1>

LCO 3.4.3 RCS pressure, RCS temperature, and RCS heatup and cooldown rates shall be maintained within the limits specified in the PTLR.

<DOC A.3>

APPLICABILITY: At all times.

ACTIONS

<DOC M.1>

<DOC M.1>

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. ----------NOTE---------- Required Action A.2 shall be completed whenever this Condition is entered. ---------- Requirements of LCO not met in MODE 1, 2, 3, or 4.	A.1	Restore parameter(s) to within limits.	30 minutes
	AND		
	A.2	Determine RCS is acceptable for continued operation.	72 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1	Be in MODE 3.	6 hours
	AND		
	B.2	Be in MODE 5 with RCS pressure < ~~[500]~~ psig.	36 hours

X.1

(continued)

ACTIONS (continued)

<CTS>

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. ---------NOTE--------- Required Action C.2 shall be completed whenever this Condition is entered. ---------- Requirements of LCO not met any time in other than MODE 1, 2, 3, or 4.	C.1 Initiate action to restore parameter(s) to within limits.	Immediately
	AND	
	C.2 Determine RCS is acceptable for continued operation.	Prior to entering MODE 4

<DOC M.1>

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.3.1	----------NOTE---------- Only required to be performed during RCS heatup and cooldown operations and RCS inservice leak and hydrostatic testing. ---------- Verify RCS pressure, RCS temperature, and RCS heatup and cooldown rates are within the limits specified in the PTLR.	30 minutes

<DOC M.2>

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.3 RCS Pressure and Temperature (P/T) Limits

BASES

BACKGROUND

All components of the RCS are designed to withstand effects of cyclic loads due to system pressure and temperature changes. These loads are introduced by startup (heatup) and shutdown (cooldown) operations, power transients, and reactor trips. This LCO limits the pressure and temperature changes during RCS heatup and cooldown, within the design assumptions and the stress limits for cyclic operation.

Pressure and Temperature Limits Report

The (PTLR) contains P/T limit curves for heatup, cooldown, inservice leak and hydrostatic (ISLH) testing, and data for the maximum rate of change of reactor coolant temperature (Ref. 1). PA.1

Each P/T limit curve defines an acceptable region for normal operation. The usual use of the curves is operational guidance during heatup or cooldown maneuvering, when pressure and temperature indications are monitored and compared to the applicable curve to determine that operation is within the allowable region.

The LCO establishes operating limits that provide a margin to brittle failure of the reactor vessel and piping of the reactor coolant pressure boundary (RCPB). The vessel is the component most subject to brittle failure, and the LCO limits apply mainly to the vessel. The limits do not apply to the pressurizer, which has different design characteristics and operating functions.

10 CFR 50, Appendix G (Ref. 2), requires the establishment of P/T limits for specific material fracture toughness requirements of the RCPB materials. Reference 2 requires an adequate margin to brittle failure during normal operation, anticipated operational occurrences, and system hydrostatic tests. It mandates the use of the American Society of Mechanical Engineers (ASME) Code, Section III, Appendix G (Ref. 3).

The neutron embrittlement effect on the material toughness is reflected by increasing the nil ductility reference temperature (RT_{NDT}) as exposure to neutron fluence increases.

(continued)

BASES

BACKGROUND (continued)

The actual shift in the RT_{NDT} of the vessel material will be established periodically by removing and evaluating the irradiated reactor vessel material specimens, in accordance with ASTM E 185 (Ref. 4) and Appendix H of 10 CFR 50 (Ref. 5). The operating P/T limit curves will be adjusted, as necessary, based on the evaluation findings and the recommendations of Regulatory Guide 1.99 (Ref. 6).

The P/T limit curves are composite curves established by superimposing limits derived from stress analyses of those portions of the reactor vessel and head that are the most restrictive. At any specific pressure, temperature, and temperature rate of change, one location within the reactor vessel will dictate the most restrictive limit. Across the span of the P/T limit curves, different locations are more restrictive, and, thus, the curves are composites of the most restrictive regions.

The heatup curve represents a different set of restrictions than the cooldown curve because the directions of the thermal gradients through the vessel wall are reversed. The thermal gradient reversal alters the location of the tensile stress between the outer and inner walls.

The criticality limit curve includes the Reference 2 requirement that it be ≥ 40°F above the heatup curve or the cooldown curve, and not less than the minimum permissible temperature for ISLH testing. However, the criticality curve is not operationally limiting; a more restrictive limit exists in LCO 3.4.2, "RCS Minimum Temperature for Criticality."

The consequence of violating the LCO limits is that the RCS has been operated under conditions that can result in brittle failure of the RCPB, possibly leading to a nonisolable leak or loss of coolant accident. In the event these limits are exceeded, an evaluation must be performed to determine the effect on the structural integrity of the RCPB components. The ASME Code, Section XI, Appendix E (Ref. 7), provides a recommended methodology for evaluating an operating event that causes an excursion outside the limits.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The P/T limits are not derived from Design Basis Accident (DBA) analyses. They are prescribed during normal operation to avoid encountering pressure, temperature, and temperature rate of change conditions that might cause undetected flaws to propagate and cause nonductile failure of the RCPB, an unanalyzed condition. Reference 1 establishes the methodology for determining the P/T limits. Although the P/T limits are not derived from any DBA, the P/T limits are acceptance limits since they preclude operation in an unanalyzed condition.

RCS P/T limits satisfy Criterion 2 of ~~the NRC Policy Statement~~ 10 CFR 50.36. PA.1

LCO

The two elements of this LCO are:

a. The limit curves for heatup, cooldown, and ISLH testing; and

b. Limits on the rate of change of temperature.

The LCO limits apply to all components of the RCS pressure boundary except the pressurizer. These limits define allowable operating regions and permit a large number of operating cycles while providing a wide margin to nonductile failure.

The limits for the rate of change of temperature control the thermal gradient through the vessel wall and are used as inputs for calculating the heatup, cooldown, and ISLH testing P/T limit curves. Thus, the LCO for the rate of change of temperature restricts stresses caused by thermal gradients and also ensures the validity of the P/T limit curves. PA.1

Insert: B3.4-11-01

Violating the LCO limits places the reactor vessel outside of the bounds of the stress analyses and can increase stresses in other RCPB components. The consequences depend on several factors, as follow: a

a. The severity of the departure from the allowable operating P/T regime or the severity of the rate of change of temperature;

(continued)

INSERT: B 3.4-11-01

PA.1

Heatup and cooldown limits are specified in hourly increments (i.e., the heatup and cooldown limits are based on the temperature change averaged over a one hour period).

BASES

LCO (continued)

b. The length of time the limits were violated (longer violations allow the temperature gradient in the thick vessel walls to become more pronounced); and

c. The existences, sizes, and orientations of flaws in the vessel material.

APPLICABILITY

The RCS P/T limits LCO provides a definition of acceptable operation for prevention of nonductile failure in accordance with 10 CFR 50, Appendix G (Ref. 2). Although the P/T limits were developed to provide guidance for operation during heatup or cooldown (MODES 3, 4, and 5) or ISLH testing, their Applicability is at all times in keeping with the concern for nonductile failure. The limits do not apply to the pressurizer.

During MODES 1 and 2, other Technical Specifications provide limits for operation that can be more restrictive than or can supplement these P/T limits. LCO 3.4.1, "RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits"; LCO 3.4.2, "RCS Minimum Temperature for Criticality"; and Safety Limit 2.1, "Safety Limits," also provide operational restrictions for pressure and temperature and maximum pressure. Furthermore, MODES 1 and 2 are above the temperature range of concern for nonductile failure, and stress analyses have been performed for normal maneuvering profiles, such as power ascension or descent.

ACTIONS

A.1 and A.2

Operation outside the P/T limits during MODE 1, 2, 3, or 4 must be corrected so that the RCPB is returned to a condition that has been verified by stress analyses.

The 30 minute Completion Time reflects the urgency of restoring the parameters to within the analyzed range. Most violations will not be severe, and the activity can be accomplished in this time in a controlled manner.

Besides restoring operation within limits, an evaluation is required to determine if RCS operation can continue. The

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

evaluation must verify the RCPB integrity remains acceptable and must be completed before continuing operation. Several methods may be used, including comparison with pre-analyzed transients in the stress analyses, new analyses, or inspection of the components.

ASME Code, Section XI, Appendix E (Ref. 7), may be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline.

The 72 hour Completion Time is reasonable to accomplish the evaluation. The evaluation for a mild violation is possible within this time, but more severe violations may require special, event specific stress analyses or inspections. A favorable evaluation must be completed before continuing to operate.

Condition A is modified by a Note requiring Required Action A.2 to be completed whenever the Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the excursion outside the allowable limits. Restoration alone per Required Action A.1 is insufficient because higher than analyzed stresses may have occurred and may have affected the RCPB integrity.

B.1 and B.2

If a Required Action and associated Completion Time of Condition A are not met, the plant must be placed in a lower MODE because either the RCS remained in an unacceptable P/T region for an extended period of increased stress or a sufficiently severe event caused entry into an unacceptable region. Either possibility indicates a need for more careful examination of the event, best accomplished with the RCS at reduced pressure and temperature. In reduced pressure and temperature conditions, the possibility of propagation with undetected flaws is decreased.

If the required restoration activity cannot be accomplished within 30 minutes, Required Action B.1 and Required Action B.2 must be implemented to reduce pressure and temperature.

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

If the required evaluation for continued operation cannot be accomplished within 72 hours or the results are indeterminate or unfavorable, action must proceed to reduce pressure and temperature as specified in Required Action B.1 and Required Action B.2. A favorable evaluation must be completed and documented before returning to operating pressure and temperature conditions.

Pressure and temperature are reduced by bringing the plant to MODE 3 within 6 hours and to MODE 5 with RCS pressure < [500] psig within 36 hours. X.1

Insert: B3.4-14-01

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.

C.1 and C.2

Actions must be initiated immediately to correct operation outside of the P/T limits at times other than when in MODE 1, 2, 3, or 4, so that the RCPB is returned to a condition that has been verified by stress analysis.

The immediate Completion Time reflects the urgency of initiating action to restore the parameters to within the analyzed range. Most violations will not be severe, and the activity can be accomplished in this time in a controlled manner.

Besides restoring operation within limits, an evaluation is required to determine if RCS operation can continue. The evaluation must verify that the RCPB integrity remains acceptable and must be completed prior to entry into MODE 4. Several methods may be used, including comparison with pre-analyzed transients in the stress analyses, or inspection of the components.

ASME Code, Section XI, Appendix E (Ref. 7), may be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline.

(continued)

INSERT: B 3.4-14-01

significantly reduced and limited by LCO 3.4.12, Low Temperature Overpressure Protection (LTOP),

BASES

ACTIONS

C.1 and C.2 (continued)

Condition C is modified by a Note requiring Required Action C.2 to be completed whenever the Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the excursion outside the allowable limits. Restoration alone per Required Action C.1 is insufficient because higher than analyzed stresses may have occurred and may have affected the RCPB integrity.

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1

Verification that operation is within the PTLR limits is required every 30 minutes when RCS pressure and temperature conditions are undergoing planned changes. This Frequency is considered reasonable in view of the control room indication available to monitor RCS status. Also, since temperature rate of change limits are specified in hourly increments, 30 minutes permits assessment and correction for minor deviations within a reasonable time.

PA.1

Insert: B3.4-15-01

Surveillance for heatup, cooldown, or ISLH testing may be discontinued when the definition given in the relevant plant procedure for ending the activity is satisfied.

This SR is modified by a Note that only requires this SR to be performed during system heatup, cooldown, and ISLH testing. No SR is given for criticality operations because LCO 3.4.2 contains a more restrictive requirement.

REFERENCES

1. WCAP-7924-A, ~~April 1975~~. July 1972
2. 10 CFR 50, Appendix G.
3. ASME, Boiler and Pressure Vessel Code, Section III, Appendix G.
4. ASTM E 185-~~82~~ 70, ~~July 1982~~.
5. 10 CFR 50, Appendix H.

(continued)

PA.1

INSERT: B 3.4-15-01

Heatup and cooldown limits are specified in hourly increments (i.e., the heatup and cooldown limits are based on the temperature change averaged over a one hour period).

BASES

REFERENCES (continued)

6. Regulatory Guide 1.99, Revision 2, May 1988.

7. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix E.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.3:
"RCS Pressure and Temperature (P/T) Limits"

PART 6:

Justification of Differences between

NUREG-1431 and IP3 ITS

JUSTIFICATION OF DIFFERENCES FROM NUREG-1431
ITS SECTION 3.4.3 - RCS Pressure and Temperature (P/T) Limits

RETENTION OF EXISTING REQUIREMENT (CURRENT LICENSING BASIS)

None

PLANT-SPECIFIC WORDING PREFERENCE OR MINOR EDITORIAL IMPROVEMENT

PA.1 Corrected typographical error or made a minor editorial improvement to improve clarity and ensure requirements are fully understood and consistently applied. There are no technical changes to requirements as specified in NUREG 1431, Rev. 1; therefore, this change is not a significant or generic deviation from NUREG 1431, Rev 1.

PLANT-SPECIFIC DIFFERENCE IN THE DESIGN OR DESIGN BASIS

DB.1 Design or implementation details are incorporated or revised as necessary to more precisely describe IP3 current design or practice. These changes are intended to describe the design, improve clarity, or ensure requirements are fully understood and consistently applied. Unless identified and described blow, these changes are self-explanatory. A detailed description of the design, accident analysis assumptions, and Operability requirements are incorporated into the IP3 ITS Bases. These changes maintain the IP3 current licensing basis except as identified and justified in the CTS/ITS discussion of changes.

DIFFERENCE BASED ON A GENERIC CHANGE TRAVELER FOR NUREG-1431

None

DIFFERENCE FOR ANY REASON OTHER THAN ABOVE

X.1 NUREG 1431, Rev.1, LCO 3.4.3, Required Action B.2, requires that the reactor be placed in MODE 5 with RCS pressure < 500 psig if Required Actions or Completion Times are not met after RCS pressure, RCS temperature, and RCS heatup and cooldown rate limits are exceeded.

Under the same conditions, IP3 ITS NUREG 1431, Rev.1, LCO 3.4.3,

Required Action B.2, requires only that the reactor be in Mode 5. No pressure restriction is specified because in Mode 5 RCS pressure is significantly reduced and limited by LCO 3.4.12, Low Temperature Overpressure Protection (LTOP). Based on existing LTOP limits, RCS pressure is expected to be maintained < 500 psig whenever the reactor is in Mode 5. This change is needed to eliminate potential ambiguities and to simply comply with LCO 3.4.3, Required Action B.2. This change has no significant adverse impact on safety.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.4:
"RCS Loops - MODES 1 and 2"

PART 1:

Indian Point 3
Improved Technical Specifications and Bases

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.4 RCS Loops – MODES 1 and 2

LCO 3.4.4 Four RCS loops shall be OPERABLE and in operation.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Requirements of LCO not met.	A.1 Be in MODE 3.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.4.4.1 Verify each RCS loop is in operation.	12 hours

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.4 RCS Loops – MODES 1 and 2

BASES

BACKGROUND

The primary function of the RCS is removal of the heat generated in the fuel due to the fission process, and transfer of this heat, via the steam generators (SGs), to the secondary plant.

The secondary functions of the RCS include:

a. Moderating the neutron energy level to the thermal state, to increase the probability of fission;

b. Improving the neutron economy by acting as a reflector;

c. Carrying the soluble neutron poison, boric acid;

d. Providing a second barrier against fission product release to the environment; and

e. Removing the heat generated in the fuel due to fission product decay following a unit shutdown.

The reactor coolant is circulated through four loops connected in parallel to the reactor vessel, each containing an SG, a reactor coolant pump (RCP), and appropriate flow and temperature instrumentation for both control and protection. The reactor vessel contains the fuel. The SGs provide the heat sink to the isolated secondary coolant. The RCPs circulate the coolant through the reactor vessel and SGs at a sufficient rate to ensure proper heat transfer and prevent fuel damage. This forced circulation of the reactor coolant ensures mixing of the coolant for proper boration and chemistry control.

Calculations have shown that reactor heat equivalent to 10% rated power can be removed via the steam generators with natural circulation without violating DNBR limits. This analysis assumed conservative flow resistances including steam generator tube plugging and a lock rotor in each loop (Ref.1).

BASES

APPLICABLE SAFETY ANALYSES

Safety analyses contain various assumptions for the design bases accident initial conditions including RCS pressure, RCS temperature, reactor power level, core parameters, and safety system setpoints. The important aspect for this LCO is the reactor coolant forced flow rate, which is represented by the number of RCS loops in service.

Both transient and steady state analyses have been performed to establish the effect of flow on the departure from nucleate boiling (DNB). The transient and accident analyses for the plant have been performed assuming four RCS loops are in operation. The majority of the plant safety analyses are based on initial conditions at high core power or zero power. The accident analyses that are most important to RCP operation are the four pump coastdown, single pump locked rotor, single pump (broken shaft or coastdown), and rod withdrawal events (Ref. 1).

Steady state DNB analysis has been performed for the four RCS loop operation. For four RCS loop operation, the steady state DNB analysis, which generates the pressure and temperature Safety Limit (SL) (i.e., the departure from nucleate boiling ratio (DNBR) limit) assumes a maximum power level of 109% RTP. This is the design overpower condition for four RCS loop operation. The value for the accident analysis stet of the nuclear overpower (high flux) trip is 108% and is based on an analysis assumption that bounds possible instrumentation errors. The DNBR limit defines a locus of pressure and temperature points that result in a minimum DNBR greater than or equal to the critical heat flux correlation limit.

The plant is designed to operate with all RCS loops in operation to maintain DNBR above the SL, during all normal operations and anticipated transients. By ensuring heat transfer in the nucleate boiling region, adequate heat transfer is provided between the fuel cladding and the reactor coolant.

RCS Loops – MODES 1 and 2 satisfy Criterion 2 of 10 CFR 50.36.

BASES

LCO

The purpose of this LCO is to require an adequate forced flow rate for core heat removal. Flow is represented by the number of RCPs in operation for removal of heat by the SGs. To meet safety analysis acceptance criteria for DNB, four pumps are required at rated power.

An OPERABLE RCS loop consists of an OPERABLE RCP in operation providing forced flow for heat transport and an OPERABLE SG in accordance with the Steam Generator Surveillance Program.

APPLICABILITY

In MODES 1 and 2, the reactor is critical and thus has the potential to produce maximum THERMAL POWER. Thus, to ensure that the assumptions of the accident analyses remain valid, all RCS loops are required to be OPERABLE and in operation in these MODES to prevent DNB and core damage.

The decay heat production rate is much lower than the full power heat rate. As such, the forced circulation flow and heat sink requirements are reduced for lower, noncritical MODES as indicated by the LCOs for MODES 3, 4, and 5.

Operation in other MODES is covered by:

LCO 3.4.5, "RCS Loops – MODE 3";
LCO 3.4.6, "RCS Loops – MODE 4";
LCO 3.4.7, "RCS Loops – MODE 5, Loops Filled";
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

A.1

If the requirements of the LCO are not met, the Required Action is to reduce power and bring the plant to MODE 3. This lowers power level and thus reduces the core heat removal needs and minimizes the possibility of violating DNB limits.

BASES

ACTIONS

A.1 (continued)

The 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 safety systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.4.1

This SR requires verification every 12 hours that each RCS loop is in operation. Verification can be based on flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal while maintaining the margin to DNB. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RCS loop performance.

REFERENCES

1. FSAR, Section 14.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.4:
"RCS Loops - MODES 1 and 2"

PART 2:

CURRENT TECHNICAL SPECIFICATION PAGES

Annotated to show differences between CTS and ITS

CTS pages and associated TSCRs annotated for this ITS Specification :

CTS Page No.	Effective Amendment	Annotated Amendment	TSCR No.	TSCR Description	ITS Status of TSCR
LIC 3	181	181	No TSCRs	No TSCRs for this Page	N/A
3.1-2	179	179	No TSCRs	No TSCRs for this Page	N/A
3.1-7	121	121	No TSCRs	No TSCRs for this Page	N/A

C. This amended license shall be deemed to contain and is subject to the conditions specified in the following Commission regulations in 10 CFR Chapter I: Part 20, Section 30.34 of Part 30, Section 40.41 of Part 40, Sections 50.54 and 50.59 of Part 50, and Section 70.32 of Part 70; and is subject to all applicable provisions of the act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

The licensee is authorized to operate the facility at steady state reactor core Power levels not in excess of 3025 megawatts thermal (100% of rated power). — Amdt.17 8-18-78

(2) Technical Specifications

The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 176, are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications. — Amdt. ~~176~~ 181 8-11-97

(3) ~~Less Than Four Loop Operation~~ A.3

(Deleted)

~~The licensee shall not operate the reactor at power levels above P-7 (as defined in Section 7.2 of the Final Facility Description and Safety Analysis Report) with less than four (4) reactor coolant loops in operation until safety analyses for less than four loop operation have been submitted by the licensee and approval for less than four loop operation at power levels above P-7 has been granted by the Commission and amendment of this license.~~

(4) Pressurizer Weld Inspection

The results of the UT inspection of pressurizer weld L-1 (ref. Appendix A Technical Specification 4.2.5.f) shall be reported to the NRC and approval of the results obtained prior to return to power operation following the second refueling shutdown." — Amdt.16 8-11-78

D. (DELETED) — Amdt.46 2-16-83

E. (DELETED) — Amdt.37 5-14-81

Add SR 3.4.4.1 M.2 A.1 A.2

SEE ITS 3.4.7 3.4.8

d. When the reactor coolant system T_{avg} is less than 200°F, but not in the refueling operation condition, and as permitted during special plant evolutions, at least one residual heat removal pump (connected to the Reactor Coolant System) shall be in operation. This RHR pump may be out of service for up to 1 hour provided no operations are permitted that would cause dilution of the reactor coolant system boron concentration, and core outlet temperature is maintained at least 10°F below saturation temperature.

LCO 3.4.4 and Applicability

~~e.~~ When the reactor is ~~critical and above 2% rated power, except for natural circulation tests~~, at least two reactor coolant pumps shall be in operation. A.4 four Mode 1 and 2 A.1

LCO 3.4.4 and Applicability

~~f.~~ ~~The reactor shall not be operated at power levels above 10%~~ rated power with less than four (4) reactor coolant loops in operation. M.1

Req. Act A.1

~~g.~~ If the requirements of 3.1.A.1.e and 3.1.A.1.f above cannot be satisfied, the reactor shall be brought to the not shutdown Mode 3 condition within 1 hour. 6 A.1 L.1

SEE ITS 3.4.12

h. A reactor coolant pump (RCP) may not be started (or jogged) when the RCS cold leg temperature (T_{cold}) is at or below 319°F, unless RCS make up is not in excess of RCS losses, and one of the following requirements is met:

(1) The OPS is operable, steam generator pressure is not decreasing, and the temperature of each steam generator is less than or equal to the coldest T_{cold};

Or

(2) The OPS is operable, the temperature of the hottest steam generator exceeds the coldest T_{cold} by no more than 64°F, pressurizer level is at or below 73 percent, and T_{cold} is as per Figure 3.1.A-1;

Or

(3) With OPS inoperable, steam generator pressure is not decreasing, the temperature of each steam generator is less than or equal to the coldest T_{cold}, pressurizer level is at or below 73 percent, and the RCS pressure does not exceed that given by Fig. 3.1.A-2. The pressurizer level must be further restricted per Figures 3.1.A-5 and 3.1.A-6 if operation below 319°F exceeds 8 hours.

Basis

When the boron concentration of the Reactor Coolant System is to be reduced the process must be uniform to prevent sudden reactivity changes in the reactor. Mixing of the reactor coolant will be sufficient to maintain a uniform boron concentration if at least one reactor coolant pump or one residual heat removal pump is running while the change is taking place. The residual heat removal pump will circulate the primary system volume in approximately one half hour. The pressurizer is of no concern because of the low pressurizer volume and because the pressurizer boron concentration will be higher than that of the rest of the reactor coolant. A.1

Heat transfer analyses show that reactor heat equivalent to 10% of rated power (P-7) can be removed with natural circulation only (1); hence, the requirement for one operating RCP above 350°F and two operating RCP's above 2% rated power provides a substantial safety factor. In addition, a single RCP or RHR pump (connected to the RCS) provides sufficient heat removal capability for removing decay heat.

The restriction on control bank withdrawal with less than four reactor coolant pumps operating when the reactor is subcritical and RCS T_{avg} is greater than 350°F is necessary to conform with the assumptions used in the transient analyses for the uncontrolled control rod withdrawal event from subcritical condition. The FSAR safety analysis for uncontrolled control rod assembly withdrawal from a subcritical condition assumes all four reactor coolant pumps to be operating within the temperature range of concern. Using this assumption the DNB design basis is satisfied for the combination of the two banks of the maximum combined worth withdrawn at maximum speed. Since there is no mechanism by which the control rods can be automatically withdrawn due to a control system error when T_{avg} is between 350°F and the no-load temperature, such an event can only be initiated as a result of human error during rod manipulation. Prohibiting control bank withdrawal with less than four RCPs operating provides assurance that the plant is operated within the accident analysis assumptions.

The reactor shall not be operated at power levels above 10% rated power with less than four (4) reactor coolant loops in operation until safety analyses for less than four loop operation have been submitted by the licensee and approval for less than four loop operation at power levels above 10% rated power has been granted by the Commission. (See license condition 2.C. (7))

Each of the pressurizer code safety valves is designed to relieve 420,000 lbs. per hr. of saturated steam at the valve set point.

If no residual heat were removed by the Residual Heat Removal System the amount of steam which could be generated at safety valve relief pressure would be less than half the capacity of a single valve. One valve therefore provides adequate protection for overpressurization.

The combined capacity of the three pressurizer safety valves is greater than the maximum surge rate resulting from complete loss of load (2) without a direct reactor trip or any other control.

Amendment No. 48, 53, 84, 121

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.4:
"RCS Loops - MODES 1 and 2"

PART 3:

DISCUSSION OF CHANGES

Differences between CTS and ITS

DISCUSSION OF CHANGES
ITS SECTION 3.4.4 - RCS Loops – MODES 1 and 2

ADMINISTRATIVE

A.1 In the conversion of the Indian Point Unit 3 Current Technical Specifications (CTS) to the plant specific Improved Technical Specifications (ITS) certain wording preferences or conventions are adopted which do not result in technical changes (either actual or interpretational). Additionally, editorial changes, reformatting, and revised numbering are adopted to make ITS consistent with the conventions in NUREG-1431, Standard Technical Specifications, Westinghouse Plants, Rev. 1, i.e., the improved Standard Technical Specifications.

The CTS Bases are deleted and replaced with comprehensive ITS Bases that are designed to support interpretation and implementation of the associated Technical Specifications. The Bases explain, clarify, and document the reasons (i.e., bases) for the associated Technical Specifications, and reflect the IP3 plant specific design, analyses, and licensing basis. In accordance with 10 CFR 50.36(a), the ITS Bases are included with the proposed ITS conversion application; however, deletion of the CTS Bases and the adoption of the ITS Bases is an administrative change with no impact on safety.

A.2 CTS Limiting Conditions for Operation (LCOs) and Surveillance Requirements (SRs) include statements of the objective and the applicability. The CTS statements of objective and applicability are deleted because these statements do not establish any requirements and do not provide any guidance for the application of CTS requirements. Therefore, deletion of these statements has no significant adverse impact on safety.

A.3 Facility Operating License DPR-64, paragraph 2.C (3), Less Than Four Loop Operation, specifies that the reactor shall not be operated at power levels above P-7 (as defined in Section 7.2 of the Final Facility Description and Safety Analysis Report (i.e., 10% RTP)) with less than four (4) reactor coolant loops in operation until safety analyses for less than four loop operation have been submitted by the licensee and

approval for less than four loop operation at power levels above P-7 has been granted by the Commission and amendment of this license. However, CTS 3.1.A.1.b.2 requires 4 reactor coolant pumps in operation prior to withdrawal of any control banks which is more restrictive than Facility Operating License DPR-64, paragraph 2.C (3).

ITS LCO 3.4.4 maintains the same requirement in that ITS LCO 3.4.4 requires four reactor coolant pumps Operable and in operation at all times in Mode 1 and 2 (See ITS 3.4.4, DOC M.1). Therefore, Facility Operating License DPR-64, paragraph C (3), is deleted. This is an administrative change with no impact on safety because ITS LCO 3.4.4 maintains the requirements of CTS 3.1.A.1.b.2 which are more restrictive than Facility Operating License DPR-64, paragraph C (3).

A.4 CTS 3.1.A.1.e and CTS 3.1.A.1.f require reactor coolant pumps in operation when the reactor is at specified power levels. ITS LCO 3.4.4 requires that RCS loops be Operable and in operation with the ITS 3.4.4 Bases providing the clarification that this means an Operable reactor coolant pump (RCP) in operation providing forced flow for heat transport and an Operable steam generator (SG) in accordance with the Steam Generator Tube Surveillance Program. This is an administrative change with no impact on safety because the ITS is a more specific statement of the existing requirements.

A.5 CTS 3.1.A.1.e requires reactor coolant pumps in operation when the reactor is at specified power levels except during natural circulation tests. ITS LCO 3.4.4 maintains requirements for reactor coolant pumps in operation when the reactor is at specified power levels; however, an exception for natural circulation tests is not provided. Natural circulation tests are not normally performed at IP3. Appropriate Technical Specification changes will be prepared and submitted if natural circulation tests are needed. Therefore, deletion of RCP operation requirement during natural circulation tests is an administrative change with no adverse impact on safety.

DISCUSSION OF CHANGES
ITS SECTION 3.4.4 - RCS Loops – MODES 1 and 2

MORE RESTRICTIVE

M.1 CTS 3.1.A.1.e requires 2 reactor coolant pumps in operation when the reactor is critical and above 2% rated power. CTS 3.1.A.1.f requires 4 reactor coolant loops in operation when above 10% rated power. CTS 3.1.A.1.b.2 requires 4 reactor coolant pumps in operation prior to withdrawal of any control banks (even though 2 RCPs in operation is the assumption of a startup rod withdrawal accident).

ITS 3.4.4, RCS Loops - Modes 1 and 2, clarifies these requirements in that 4 reactor coolant pumps must be Operable and in operation in Modes 1 and 2 (i.e., during reactor startup and whenever the reactor is critical).

This change is needed to clarify existing requirements because transient and accident analyses generally have been performed assuming 4 RCS loops in operation. Therefore, this change ensures that full reactor coolant system flow is established during startup and whenever the reactor is critical. This more restrictive change is acceptable because it does not introduce any operation which is un-analyzed while requiring more conservative requirements for reactor coolant flow at low power levels. Therefore, this change has no adverse impact on safety.

M.2 CTS 3.1.A.1.e and CTS 3.1.A.1.f establish requirements for the minimum number of reactor coolant loops Operable and in operation; however, no surveillance tests are established to verify that this requirement is met. ITS SR 3.4.4.1 is added to verify every 12 hours that each RCS loop is in operation. The ITS SR 3.4.4.1 Bases clarify that this requirement can be satisfied using flow rate, temperature, or pump status monitoring sufficient to help ensure that forced flow is providing heat removal. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RCS loop performance. This more restrictive change is acceptable because it does not introduce any operation which is un-analyzed while requiring periodic verification that each RCS loop is operating as required by the LCO. Therefore, this change has no adverse impact on safety.

DISCUSSION OF CHANGES
ITS SECTION 3.4.4 - RCS Loops – MODES 1 and 2

LESS RESTRICTIVE

L.1 CTS 3.1.A.1.g requires that the reactor be placed in hot shutdown (Mode 3) within 1 hour if the required number of reactor coolant loops are not in operation. Under the same conditions, ITS LCO 3.4.4, Required Action A.1, allows 6 hours to place the plant in Mode 3. This change is acceptable because in those cases where a rapid shutdown is required because of reduced RCS flow, automatic reactor trip functions are provided by the reactor protection system. Otherwise, the failure to meet requirements for 4 RCPs Operable and in operation warrants an orderly shutdown and 6 hours is reasonable to reach Mode 3 from full power conditions in an orderly manner and without challenging safety systems. Therefore, this change has no significant adverse impact on safety.

REMOVED DETAIL

None

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.4:
"RCS Loops - MODES 1 and 2"

PART 4:

No Significant Hazards Considerations
for
Changes between CTS and ITS
that are
Less Restrictive

No Significant Hazard Considerations for Changes that are Administrative, More Restrictive, and Removed Details are the same for all Packages. A Copy is included at the end of the Package.

NO SIGNIFICANT HAZARDS EVALUATION
ITS SECTION 3.4.4 - RCS Loops – MODES 1 and 2

LESS RESTRICTIVE
("L.1" Labeled Comments/Discussions)

New York Power Authority has evaluated the proposed Technical Specification change identified as "Less Restrictive" in accordance with the criteria set forth in 10 CFR 50.92, and has determined that the proposed change does not involve a significant hazards consideration. The bases for the determination that the proposed changes do not involve a significant hazards consideration are discussed below.

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

   This change increases the time allowed to place the plant in hot shutdown (i.e., Mode 3) when fewer than the required number of reactor coolant system loops are in operation from the 1 hour specified in CTS to the 6 hours permitted by ITS. This change will not result in a significant increase in the probability of an accident previously evaluated because the time permitted to perform a required reactor shutdown when fewer than the required number of reactor coolant loops are in operation is not the initiator of any analyzed event. This change will not result in a significant increase in the consequences of an accident previously evaluated because in those cases where a rapid shutdown is required to compensate for reduced RCS flow, automatic reactor trip functions are provided by the reactor protection system. Otherwise, the failure to meet requirements for 4 RCPs Operable and in operation warrants an orderly shutdown and 6 hours is reasonable to reach Mode 3 from full power conditions in an orderly manner and without challenging safety systems.

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

   The proposed changes will not involve any physical changes to plant systems, structures, or components (SSC). The changes in normal Plant operation are consistent with the current safety analysis assumptions because allowing 6 hours to complete an orderly shutdown to Mode 3 is consistent with current operating practice. Therefore, these changes

will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

This change does not involve a significant reduction in a margin of safety because in those cases where a rapid shutdown is required to compensate for reduced RCS flow, automatic reactor trip functions are provided by the reactor protection system. Otherwise, the failure to meet requirements for 4 RCPs Operable and in operation warrants an orderly shutdown and 6 hours is reasonable to reach Mode 3 from full power conditions in an orderly manner and without challenging safety systems.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.4:
"RCS Loops - MODES 1 and 2"

PART 5:

NUREG-1431
Annotated to show differences between
NUREG-1431 and ITS

Status of NUREG 1431 Generic Changes for ITS 3.4.4

This ITS Specification is based on NUREG-1431 Specification No. 3.4.4
as modified by the following Generic Changes:

OG No.	TSTF No.	Generic Change Description	NRC STATUS	IP3 STATUS	JD No.
N/A	N/A	NO GENERIC CHANGES ARE POSTED AGAINST THIS SPECIFICATION.	Not Applicable	Not Applicable	N/A

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.4 RCS Loops—MODES 1 and 2

<3.1.A.1.e>
<3.1.A.1.f>
<DOC M.1>

LCO 3.4.4 ~~[Four]~~ RCS loops shall be OPERABLE and in operation.

APPLICABILITY: MODES 1 and 2.

ACTIONS

<3.1.A.1.g>
<DOC L.1>

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Requirements of LCO not met.	A.1 Be in MODE 3.	6 hours

SURVEILLANCE REQUIREMENTS

<DOC M.2>

SURVEILLANCE	FREQUENCY
SR 3.4.4.1 Verify each RCS loop is in operation.	12 hours

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.4 RCS Loops—MODES 1 and 2

BASES

BACKGROUND

The primary function of the RCS is removal of the heat generated in the fuel due to the fission process, and transfer of this heat, via the steam generators (SGs), to the secondary plant.

The secondary functions of the RCS include:

a. Moderating the neutron energy level to the thermal state, to increase the probability of fission;

b. Improving the neutron economy by acting as a reflector;

c. Carrying the soluble neutron poison, boric acid;

d. Providing a second barrier against fission product release to the environment; and

e. Removing the heat generated in the fuel due to fission product decay following a unit shutdown.

The reactor coolant is circulated through ~~[~~four~~]~~ loops connected in parallel to the reactor vessel, each containing an SG, a reactor coolant pump (RCP), and appropriate flow and temperature instrumentation for both control and protection. The reactor vessel contains the ~~clad~~ fuel. The SGs provide the heat sink to the isolated secondary coolant. The RCPs circulate the coolant through the reactor vessel and SGs at a sufficient rate to ensure proper heat transfer and prevent fuel damage. This forced circulation of the reactor coolant ensures mixing of the coolant for proper boration and chemistry control.

Insert: B 3.4-17-01

APPLICABLE SAFETY ANALYSES

Safety analyses contain various assumptions for the design bases accident initial conditions including RCS pressure, RCS temperature, reactor power level, core parameters, and safety system setpoints. The important aspect for this LCO is the reactor coolant forced flow rate, which is represented by the number of RCS loops in service.

(continued)

DB.1

INSERT: B 3.4-17-01

Calculations have shown that reactor heat equivalent to 10% rated power can be removed via the steam generators with natural circulation without violating DNBR limits. This analysis assumed conservative flow resistances including steam generator tube plugging and a locked rotor in each loop (Ref. 1).

BASES

APPLICABLE SAFETY ANALYSES (continued)

Both transient and steady state analyses have been performed to establish the effect of flow on the departure from nucleate boiling (DNB). The transient and accident analyses for the plant have been performed assuming [four] RCS loops are in operation. The majority of the plant safety analyses are based on initial conditions at high core power or zero power. The accident analyses that are most important to RCP operation are the [four] pump coastdown, single pump locked rotor, single pump (broken shaft or coastdown), and rod withdrawal events (Ref. 1).

Steady state DNB analysis has been performed for the [four] RCS loop operation. For [four] RCS loop operation, the steady state DNB analysis, which generates the pressure and temperature Safety Limit (SL) (i.e., the departure from nucleate boiling ratio (DNBR) limit) assumes a maximum power level of 109% RTP. This is the design overpower condition for [four] RCS loop operation. The value for the accident analysis setpoint of the nuclear overpower (high flux) trip is 107% and is based on an analysis assumption that bounds possible instrumentation errors. The DNBR limit defines a locus of pressure and temperature points that result in a minimum DNBR greater than or equal to the critical heat flux correlation limit.

108%

The plant is designed to operate with all RCS loops in operation to maintain DNBR above the SL, during all normal operations and anticipated transients. By ensuring heat transfer in the nucleate boiling region, adequate heat transfer is provided between the fuel cladding and the reactor coolant.

RCS Loops—MODES 1 and 2 satisfy Criterion 2 of the NRC Policy Statement.

10 CFR 50.36

LCO

The purpose of this LCO is to require an adequate forced flow rate for core heat removal. Flow is represented by the number of RCPs in operation for removal of heat by the SGs. To meet safety analysis acceptance criteria for DNB, [four] pumps are required at rated power.

An OPERABLE RCS loop consists of an OPERABLE RCP in operation providing forced flow for heat transport and an

(continued)

BASES

LCO (continued)

OPERABLE SG in accordance with the Steam Generator Tube Surveillance Program.

APPLICABILITY

In MODES 1 and 2, the reactor is critical and thus has the potential to produce maximum THERMAL POWER. Thus, to ensure that the assumptions of the accident analyses remain valid, all RCS loops are required to be OPERABLE and in operation in these MODES to prevent DNB and core damage.

The decay heat production rate is much lower than the full power heat rate. As such, the forced circulation flow and heat sink requirements are reduced for lower, noncritical MODES as indicated by the LCOs for MODES 3, 4, and 5.

Operation in other MODES is covered by:

LCO 3.4.5, "RCS Loops—MODE 3";
LCO 3.4.6, "RCS Loops—MODE 4";
LCO 3.4.7, "RCS Loops—MODE 5, Loops Filled";
LCO 3.4.8, "RCS Loops—MODE 5, Loops Not Filled";
LCO 3.9.8, "Residual Heat Removal (RHR) and Coolant Circulation—High Water Level" (MODE 6); and
LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation—Low Water Level" (MODE 6).

ACTIONS

A.1

If the requirements of the LCO are not met, the Required Action is to reduce power and bring the plant to MODE 3. This lowers power level and thus reduces the core heat removal needs and minimizes the possibility of violating DNB limits.

The 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 safety systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.4.1

This SR requires verification every 12 hours that each RCS loop is in operation. Verification can be based on ~~includes~~ flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal while maintaining the margin to DNB. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RCS loop performance.

REFERENCES

1. FSAR, Section ~~[ ]~~. 14

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.4:
"RCS Loops - MODES 1 and 2"

PART 6:

Justification of Differences between

NUREG-1431 and IP3 ITS

JUSTIFICATION OF DIFFERENCES FROM NUREG-1431
ITS SECTION 3.4.4 - RCS Loops – MODES 1 and 2

RETENTION OF EXISTING REQUIREMENT (CURRENT LICENSING BASIS)

None

PLANT-SPECIFIC WORDING PREFERENCE OR MINOR EDITORIAL IMPROVEMENT

PA.1 Corrected typographical error or made a minor editorial improvement to improve clarity and ensure requirements are fully understood and consistently applied. There are no technical changes to requirements as specified in NUREG 1431, Rev. 1; therefore, this change is not a significant or generic deviation from NUREG 1431, Rev 1.

PLANT-SPECIFIC DIFFERENCE IN THE DESIGN OR DESIGN BASIS

DB.1 Design or implementation details are incorporated or revised as necessary to more precisely describe IP3 current design or practice. These changes are intended to describe the design, improve clarity, or ensure requirements are fully understood and consistently applied. Unless identified and described blow, these changes are self-explanatory. A detailed description of the design, accident analysis assumptions, and Operability requirements are incorporated into the IP3 ITS Bases. These changes maintain the IP3 current licensing basis except as identified and justified in the CTS/ITS discussion of changes.

DIFFERENCE BASED ON A GENERIC CHANGE TRAVELER FOR NUREG-1431

None

DIFFERENCE FOR ANY REASON OTHER THAN ABOVE

None

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.5:
"RCS Loops - MODE 3"

PART 1:

Indian Point 3
Improved Technical Specifications and Bases

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 not be in operation for ≤ 1 hour per 8 hour period provided:

a. No operations are permitted that would cause reduction of the RCS boron concentration; and

b. Core outlet temperature is maintained ≥ 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

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. One required RCS loop not in operation, and reactor trip breakers closed and Rod Control System capable of rod withdrawal.	C.1	Restore required RCS loop to operation.	1 hour
	OR		
	C.2	De-energize all control rod drive mechanisms (CRDMs).	1 hour
D. Two required RCS loops inoperable. OR No RCS loop in operation.	D.1	De-energize all CRDMs.	Immediately
	AND		
	D.2	Suspend all operations involving a reduction of RCS boron concentration.	Immediately
	AND		
	D.3	Initiate action to restore one RCS loop to OPERABLE status and in operation.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.5.1	Verify required RCS loops are in operation.	12 hours
SR 3.4.5.2	Verify steam generator secondary side actual water level is ≥ 71% (wide range equivalent) for each required RCS loop.	12 hours
SR 3.4.5.3	Verify correct breaker alignment and indicated power are available to the required pump that is not in operation.	7 days

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.5 RCS Loops – MODE 3

BASES

BACKGROUND

In MODE 3, the primary function of the reactor coolant is removal of decay heat and transfer of this heat, via the steam generator (SG), to the secondary plant fluid. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

The reactor coolant is circulated through four RCS loops, connected in parallel to the reactor vessel, each containing an SG, and a reactor coolant pump (RCP). Appropriate flow, pressure, and temperature instrumentation are available for control, protection, and indication. The reactor vessel contains the fuel. The SGs provide the heat sink. The RCPs circulate the water through the reactor vessel and SGs at a sufficient rate to ensure proper heat transfer and prevent fuel damage.

In MODE 3, RCPs are used to provide forced circulation for heat removal during heatup and cooldown. The MODE 3 decay heat removal requirements are low enough that a single RCS loop with one RCP running is sufficient to remove core decay heat. However, two RCS loops are required to be OPERABLE to ensure redundant capability for decay heat removal.

Calculations have shown that reactor decay heat equivalent to 10% rated power can be removed via the steam generators with natural circulation. This analysis assumed conservative flow resistences including steam generator tube plugging and a lock rotor in each loop (Ref. 1).

APPLICABLE SAFETY ANALYSES

Whenever the reactor trip breakers (RTBs) are in the closed position and the control rod drive mechanisms (CRDMs) are energized, an inadvertent rod withdrawal from subcritical, resulting in a power excursion, is possible. Such a transient could be caused by a malfunction of the rod control system. In addition, the possibility of a power excursion due to the

BASES

APPLICABLE SAFETY ANALYSES (continued)

ejection of an inserted control rod is possible with the breakers closed or open. Such a transient could be caused by the mechanical failure of a CRDM.

Therefore, in MODE 3 with RTBs in the closed position and Rod Control System capable of rod withdrawal, uncontrolled control rod withdrawal from subcritical is postulated and requires at least two RCS loops to be OPERABLE and in operation to ensure that the accident analyses limits are met. For those conditions when the Rod Control System is not capable of rod withdrawal, two RCS loops are required to be OPERABLE, but only one RCS loop is required to be in operation to be consistent with MODE 3 accident analyses.

Failure to provide decay heat removal may result in challenges to a fission product barrier. The RCS loops are part of the primary success path that functions or actuates to prevent or mitigate a Design Basis Accident or transient that either assumes the failure of, or presents a challenge to, the integrity of a fission product barrier.

RCS Loops – MODE 3 satisfy Criterion 3 of 10 CFR 50.36.

LCO

The purpose of this LCO is to require that at least two RCS loops be OPERABLE. In MODE 3 with the RTBs in the closed position and Rod Control System capable of rod withdrawal, two RCS loops must be in operation. Two RCS loops are required to be in operation in MODE 3 with RTBs closed and Rod Control System capable of rod withdrawal due to the postulation of a power excursion because of an uncontrolled rod withdrawal. The required number of RCS loops in operation ensures that the Safety Limit criteria will be met for all of the postulated accidents.

With the RTBs in the open position, or the CRDMs de-energized, the Rod Control System is not capable of rod withdrawal; therefore, only one RCS loop in operation is necessary to ensure removal of decay heat from the core and homogenous boron concentration throughout the RCS. An additional RCS loop is

BASES

LCO (continued)

required to be OPERABLE to ensure redundant decay heat removal capability.

The Note permits all RCPs to be not be in operation for ≤ 1 hour per 8 hour period. The purpose of the Note is to permit performance of required tests or maintenance that can only be performed with all reactor coolant pumps not in operation. The 1 hour time period specified is acceptable because operating experience has shown that boron stratification is not a problem during this short period with no forced flow.

Utilization of the Note 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, thereby maintaining the margin to criticality. Boron reduction is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation; and

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.

An OPERABLE RCS loop consists of one OPERABLE RCP and one OPERABLE SG in accordance with the Steam Generator Tube Surveillance Program, which has the minimum water level specified in SR 3.4.5.2. An RCP is OPERABLE if it is capable of being powered and is able to provide forced flow if required.

APPLICABILITY

In MODE 3, this LCO ensures forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. The most stringent condition of the LCO, that is, two RCS loops OPERABLE and two RCS loops in operation, applies to MODE 3 with RTBs in the closed position. The least stringent

BASES

APPLICABILITY (continued)

condition, that is, two RCS loops OPERABLE and one RCS loop in operation, applies to MODE 3 with the RTBs open.

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops – MODES 1 and 2";
LCO 3.4.6, "RCS Loops – MODE 4";
LCO 3.4.7, "RCS Loops – MODE 5, Loops Filled";
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

A.1

If one required RCS loop is inoperable, redundancy for forced circulation heat removal is lost. The Required Action is restoration of the required RCS loop to OPERABLE status within the Completion Time of 72 hours. This time allowance is a justified period to be without the redundant, nonoperating loop because a single loop in operation has a heat transfer capability greater than that needed to remove the decay heat produced in the reactor core and because of the low probability of a failure in the remaining loop occurring during this period.

B.1

If restoration is not possible within 72 hours, the unit must be brought to MODE 4. In MODE 4, the unit may be placed on the Residual Heat Removal System. The additional Completion Time of 12 hours is compatible with required operations to achieve cooldown and depressurization from the existing plant conditions in an orderly manner and without challenging plant systems.

BASES

ACTIONS (continued)

C.1 and C.2

If the required RCS loop is not in operation, and the RTBs are closed and Rod Control System is capable of rod withdrawal, the Required Action is either to restore the required RCS loop to operation or to de-energize all CRDMs by opening the RTBs or de-energizing the motor generator (MG) sets. When the RTBs are in the closed position and Rod Control System are capable of rod withdrawal, it is postulated that a power excursion could occur in the event of an inadvertent control rod withdrawal. This mandates having the heat transfer capacity of two RCS loops in operation. If only one loop is in operation, the RTBs must be opened. The Completion Times of 1 hour to restore the required RCS loop to operation or de-energize all CRDMs is adequate to perform these operations in an orderly manner without exposing the unit to risk for an undue time period.

D.1, D.2, and D.3

If two required RCS loops are inoperable or no RCS loop is in operation, except as during conditions permitted by the Note in the LCO section, all CRDMs must be de-energized by opening the RTBs or de-energizing the MG sets. All operations involving a reduction of RCS boron concentration must be suspended, and action to restore one of the RCS loops to OPERABLE status and operation must be initiated. Boron dilution requires forced circulation for proper mixing, and opening the RTBs or de-energizing the MG sets removes the possibility of an inadvertent rod withdrawal. The immediate Completion Time reflects the importance of maintaining operation for forced circulation heat removal. The action to restore must be continued until one loop is restored to OPERABLE status and operation.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.5.1

This SR requires verification every 12 hours that the required loops are in operation. Verification can be based on flow rate, temperature, or pump status monitoring, which ensure that forced flow is providing heat removal. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RCS loop performance.

SR 3.4.5.2

SR 3.4.5.2 requires verification of SG OPERABILITY. SG OPERABILITY is verified by ensuring that the actual secondary side water level is ≥ 71% (wide range equivalent) for each required loop. Depending on plant conditions, either wide range or narrow range SG level instruments may be used to verify this SR is met. Operators may be required to adjust the indicated level to compensate for the effects of SG temperature. If the SG secondary side actual water level is < 71%, the tubes may become uncovered and the associated loop may not be capable of providing the heat sink for removal of the decay heat. The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to a loss of SG level.

SR 3.4.5.3

Verification that the required RCPs are OPERABLE ensures that an additional RCP can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power availability to the required RCPs.

REFERENCES None.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.5:
"RCS Loops - MODE 3"

PART 2:

CURRENT TECHNICAL SPECIFICATION PAGES

Annotated to show differences between CTS and ITS

CTS pages and associated TSCRs annotated for this ITS Specification :

CTS Page No.	Effective Amendment	Annotated Amendment	TSCR No.	TSCR Description	ITS Status of TSCR
3.1-1	121	121	No TSCRs	No TSCRs for this Page	N/A
3.1-7	121	121	No TSCRs	No TSCRs for this Page	N/A

A.1

SEE ITS 3.0

3. LIMITING CONDITIONS FOR OPERATION

For the cases where no exception time is specified for inoperable components, this time is assumed to be zero.

3.1 REACTOR COOLANT SYSTEM

A.2

~~Applicability~~

~~Applies to the operating status of the Reactor Coolant System: operational components; heatup; cooldown; criticality; activity; chemistry and leakage.~~

~~Objective~~

~~To specify those limiting conditions for operation of the Reactor Coolant System which must be met to ensure safe reactor operation.~~

Specification

~~A.~~ OPERATIONAL COMPONENTS

1. Coolant Pumps

SEE ITS 3.4.6, 3.4.7, 3.4.8

LCO 3.4.5
LCO 3.4.5, Note

~~a.~~ When a reduction is made in the boron concentration of the reactor coolant, at least one reactor coolant pump or one residual heat removal pump (connected to the Reactor Coolant System) shall be in operation.

M.1

~~b.~~ ~~(1)~~ ~~When the reactor coolant system T_{avg} is greater than 350°F and electrical power is available to the reactor coolant pumps, and as permitted during special plant evolutions,~~ at least one reactor coolant pump shall be in operation. All reactor coolant pumps may be de-energized for up to 1 hour provided no operations are permitted that would cause dilution of the reactor coolant system boron concentration, and core outlet temperature is maintained at least 10°F below saturation temperature.

Mode 3

Two loops Operable

A.3

LCO 3.4.5 Note

per 8 hour period

M.3

(2) ~~When the reactor is subcritical and reactor coolant system T_{avg} is greater than 350°F,~~ control bank withdrawal shall be prohibited unless four reactor coolant pumps are operating.

Mode 3

M.5

operable and

M.1

2

L.1

SEE ITS 3.4.6

c. When the reactor coolant system T_{avg} is greater than 200°F and less than 350°F, and as permitted during special plant evolutions, at least one reactor coolant pump or one residual heat removal pump (connected to the Reactor Coolant System) shall be in operation. All reactor coolant pumps may be de-energized with RHR not in service for up to 1 hour provided no operations are permitted that would cause dilution of the reactor coolant system boron concentration, and core outlet temperature is maintained at least 10°F below saturation temperature.

Add SR 3.4.5.1, SR 3.4.5.2 and SR 3.4.5.3 — M.4

Add Conditions A, B, C and D and associated Req. Actions — M.2

Basis

When the boron concentration of the Reactor Coolant System is to be reduced the process must be uniform to prevent sudden reactivity changes in the reactor. Mixing of the reactor coolant will be sufficient to maintain a uniform boron concentration if at least one reactor coolant pump or one residual heat removal pump is running while the change is taking place. The residual heat removal pump will circulate the primary system volume in approximately one half hour. The pressurizer is of no concern because of the low pressurizer volume and because the pressurizer boron concentration will be higher than that of the rest of the reactor coolant. A.1

Heat transfer analyses show that reactor heat equivalent to 10% of rated power (P-7) can be removed with natural circulation only (1); hence, the requirement for one operating RCP above 350°F and two operating RCP's above 2% rated power provides a substantial safety factor. In addition, a single RCP or RHR pump (connected to the RCS) provides sufficient heat removal capability for removing decay heat.

The restriction on control bank withdrawal with less than four reactor coolant pumps operating when the reactor is subcritical and RCS T_{avg} is greater than 350°F is necessary to conform with the assumptions used in the transient analyses for the uncontrolled control rod withdrawal event from subcritical condition. The FSAR safety analysis for uncontrolled control rod assembly withdrawal from a subcritical condition assumes all four reactor coolant pumps to be operating within the temperature range of concern. Using this assumption the DNB design basis is satisfied for the combination of the two banks of the maximum combined worth withdrawn at maximum speed. Since there is no mechanism by which the control rods can be automatically withdrawn due to a control system error when T_{avg} is between 350°F and the no-load temperature, such an event can only be initiated as a result of human error during rod manipulation. Prohibiting control bank withdrawal with less than four RCPs operating provides assurance that the plant is operated within the accident analysis assumptions.

The reactor shall not be operated at power levels above 10% rated power with less than four (4) reactor coolant loops in operation until safety analyses for less than four loop operation have been submitted by the licensee and approval for less than four loop operation at power levels above 10% rated power has been granted by the Commission. (See license condition 2.C. (7))

Each of the pressurizer code safety valves is designed to relieve 420,000 lbs. per hr. of saturated steam at the valve set point.

If no residual heat were removed by the Residual Heat Removal System the amount of steam which could be generated at safety valve relief pressure would be less than half the capacity of a single valve. One valve therefore provides adequate protection for overpressurization.

The combined capacity of the three pressurizer safety valves is greater than the maximum surge rate resulting from complete loss of load (2) without a direct reactor trip or any other control.

Amendment No. ~~48~~, ~~53~~, ~~84~~, 121

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.5:
"RCS Loops - MODE 3"

PART 3:

DISCUSSION OF CHANGES

Differences between CTS and ITS

DISCUSSION OF CHANGES
ITS SECTION 3.4.5 - RCS Loops - MODE 3

ADMINISTRATIVE

A.1 In the conversion of the Indian Point Unit 3 Current Technical Specifications (CTS) to the plant specific Improved Technical Specifications (ITS) certain wording preferences or conventions are adopted which do not result in technical changes (either actual or interpretational). Additionally, editorial changes, reformatting, and revised numbering are adopted to make ITS consistent with the conventions in NUREG-1431, Standard Technical Specifications, Westinghouse Plants, Rev. 1, i.e., the improved Standard Technical Specifications.

The CTS Bases are deleted and replaced with comprehensive ITS Bases that are designed to support interpretation and implementation of the associated Technical Specifications. The Bases explain, clarify, and document the reasons (i.e., bases) for the associated Technical Specifications, and reflect the IP3 plant specific design, analyses, and licensing basis. In accordance with 10 CFR 50.36(a), the ITS Bases are included with the proposed ITS conversion application; however, deletion of the CTS Bases and the adoption of the ITS Bases is an administrative change with no impact on safety.

A.2 CTS Limiting Conditions for Operation (LCOs) and Surveillance Requirements (SRs) include statements of the objective and the applicability. The CTS statements of objective and applicability are deleted because these statements do not establish any requirements and do not provide any guidance for the application of CTS requirements. Therefore, deletion of these statements has no significant adverse impact on safety.

A.3 CTS 3.1.A.1.b.1 establishes requirements for reactor coolant pump (RCP) operation when reactor coolant system (RCS) Tavg is greater than 350°F (Mode 3) but specifies that the requirements are applicable only when "electrical power is available to the reactor coolant pumps, and as permitted during special plant evolutions." However, CTS does not include any requirements for when electrical power is not available or

for special plant evolutions.

ITS LCO 3.4.5 deletes this exception to the LCO applicability because failure to meet the LCO has the same consequences and requires the same Actions regardless of the cause of the failure to meet the LCO (loss of electrical power and/or any other reason). Therefore, deletion of the exception results in no change to the existing requirements. This is an administrative change with no impact on safety because neither the CTS nor ITS provide specific requirement and/or actions for RCP operation when no electrical power is available and/or during special evolutions.

MORE RESTRICTIVE

M.1 CTS 3.1.A.1.b.1 requires 1 RCP in operation when the reactor is subcritical with reactor coolant system Tavg greater than 350°F (Mode 3); and, CTS 3.1.A.1.b.2 requires 4 RCPs in operation (See ITS 3.4.5, DOC L.1) prior to withdrawing control banks when the reactor is subcritical with reactor coolant system Tavg greater than 350°F (Mode 3).

ITS LCO 3.4.5 requires 2 RCS loops Operable in Mode 3; additionally, ITS LCO 3.4.5 requires 1 RCP in operation if control rods are not capable of withdrawal and 2 RCPs in operation (See ITS 3.4.5, DOC L.1) if control rods are capable of withdrawal.

This change, a requirement for Operable RCS loops instead of Operable RCPs, is clarified in the ITS Bases such that an Operable RCS loop consists of 1 Operable RCP and 1 Operable SG in accordance with the Steam Generator Tube Surveillance Program and that the SG must have the minimum water level specified in ITS SR 3.4.5.2. An RCP is Operable if it is capable of being powered and is able to provide forced flow.

This change is needed to ensure that the CTS requirement for an Operable RCP is correctly interpreted to mean that an RCS loop must be Operable (i.e., the RCS loop must have all of the attributes required for decay heat removal) to meet the LCO.

The change that 2 RCS loops must be Operable with one RCP in operation is needed to ensure that redundant decay heat removal capability is available if the operating reactor coolant pump fails.

These more restrictive changes are acceptable because they do not introduce any operation which is un-analyzed while ensuring that redundant decay heat removal capability is available. Therefore, this change has no adverse impact on safety.

M.2 CTS 3.1.A.1.b.1 and CTS 3.1.A.1.b.2 establish requirements for RCP operation (and loop Operability) in Mode 3; however, no Actions are specified if the LCO is not met. ITS LCO 3.4.5, Conditions A, B, C and D, are added to establish required actions and completion times when fewer than the required number of reactor coolant pumps are Operable or operating.

This change is needed to limit the time that redundant decay heat removal capability is not maintained and to limit the time that rod withdrawal is possible when the number of RCPs operating is fewer than the number assumed in the analysis of an uncontrolled control rod withdrawal from subcritical.

This more restrictive change is acceptable because it does not introduce any operation which is un-analyzed while ensuring requirements redundant decay heat removal capability and operating RCPs are met. Therefore, this change has no adverse impact on safety.

M.3 CTS 3.1.A.1.b.1 allows all reactor coolant pumps to be de-energized in Mode 3 for up to 1 hour provided no operations are permitted that would cause dilution of the reactor coolant system boron concentration, and core outlet temperature is maintained at least 10°F below saturation temperature.

ITS LCO 3.4.5, Note, provides the same allowance; however, ITS 3.4.5 limits the use of this allowance to once in any 8 hour period. This change is needed to ensure that the intent of CTS 3.1.A.1.b.1 (forced

circulation in Mode 3) is met and to eliminate any ambiguity regarding the application of an allowance that may be needed to perform required maintenance or testing in Mode 3. This more restrictive change is acceptable because it does not introduce any operation which is un-analyzed while ensuring the intent of LCO 3.4.5, to maintain forced flow in the reactor when in Mode 3, is met. Therefore, this change has no adverse impact on safety.

M.4 CTS 3.1.A.1.b.1 and CTS 3.1.A.1.b.2 establish requirements for reactor coolant pump operation when reactor coolant system Tavg is greater than 350°F (Mode 3); however, no surveillance tests are established for the periodic verification that these requirements are met.

ITS LCO 3.4.5 expands the requirement from RCPs operating to reactor coolant loops Operable (See ITS 3.4.5, DOC M.1) and includes the following SRs to ensure these LCO requirements are met: ITS SR 3.4.5.1 is added to verify every 12 hours that the minimum number of required RCS loops are in operation; ITS SR 3.4.5.2 is added to verify every 12 hours that the minimum steam generator secondary side water levels are acceptable; and, ITS SR 3.4.5.3 is added to verify every 7 days that the breaker alignment and indicated power are available to the required pump that is not in operation. This more restrictive change is acceptable because it does not introduce any operation which is un-analyzed while requiring periodic verification that each RCS loop is operating and/or operable as required by the LCO. Therefore, this change has no adverse impact on safety.

M.5 CTS 3.1.A.1.b.2 prohibits control bank withdrawal unless a specified minimum number (See ITS 3.4.5, DOC L.1) of RCPs are operating when the reactor is subcritical with Tavg greater than 350°F (Mode 3).
CTS 3.1.A.1.b.2 is intended to ensure that the assumption regarding the number of RCPs operating that is used in the analysis of an uncontrolled control rod withdrawal from subcritical condition is met whenever conditions exist that could allow an uncontrolled control rod withdrawal to occur.

To achieve the same objective, ITS LCO 3.4.5 prohibits having the rod control system capable of performing withdrawal of any control rods unless a specified minimum number (See ITS 3.4.5, DOC L.1) of RCPs are operating when in Mode 3.

This change, prohibiting having the rod control system capable of withdrawing any control rods versus prohibiting control bank withdrawal, is needed because it provides greater assurance that the assumption used in the analysis of an uncontrolled control rod withdrawal from subcritical condition regarding the number of RCPs operating is met whenever conditions exist that could allow an uncontrolled control rod withdrawal to occur.

This change is acceptable because it does not introduce any operation which is un-analyzed while reducing the potential for uncontrolled rod withdrawal when subcritical with fewer RCPs operating than is assumed in the accident analysis. Therefore, this change has no adverse impact on safety.

LESS RESTRICTIVE

L.1 CTS 3.1.A.1.b.2 requires 4 RCPs operating prior to the withdrawal of control banks (See ITS 3.4.5, DOC M.5) when the reactor is subcritical with Tavg greater than 350°F (Mode 3).

ITS LCO 3.4.5.a requires 2 RCPs operating whenever the rod control system is capable of performing withdrawal of any control rods (See ITS 3.4.5, DOC M.5) when in Mode 3. (ITS LCO 3.4.4 requires 4 RCPs in operation in Modes 1 and 2 as would occur when withdrawing control banks to approach criticality (See ITS 3.4.4, DOC M.1)).

This change, reducing the number of RCPs that must be in operation when the potential for a rod withdrawal error exists, is acceptable because both CTS 3.1.A.1.b.2 and ITS LCO 3.4.5.a are intended to ensure that the number of RCPs assumed to be operating in the analysis of an uncontrolled control rod withdrawal from subcritical condition are operating when conditions exist such that an uncontrolled control rod

withdrawal could occur. This change is acceptable because the accident analysis for uncontrolled rod withdrawal from a subcritical condition is valid when two or more reactor coolant pumps are in operation. Therefore, this change has no significant adverse impact on safety.

(Note: Analysis assumptions that only two RCPs are in operation during a startup rod withdrawal accident applies only to Vantage 5 fuel. Analyses governing earlier fuel designs assumed 4 RCPs in operation but this condition is identified as not being limited. Currently, IP3 uses Vantage 5 fuel.)

REMOVED DETAIL

None

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.5:
"RCS Loops - MODE 3"

PART 4:

No Significant Hazards Considerations for Changes between CTS and ITS that are Less Restrictive

No Significant Hazard Considerations for Changes that are Administrative, More Restrictive, and Removed Details are the same for all Packages. A Copy is included at the end of the Package.

NO SIGNIFICANT HAZARDS EVALUATION
ITS SECTION 3.4.5 - RCS Loops - MODE 3

LESS RESTRICTIVE
("L.1" Labeled Comments/Discussions)

New York Power Authority has evaluated the proposed Technical Specification change identified as "Less Restrictive" in accordance with the criteria set forth in 10 CFR 50.92, and has determined that the proposed change does not involve a significant hazards consideration. The bases for the determination that the proposed changes do not involve a significant hazards consideration are discussed below.

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

   CTS 3.1.A.1.b.2 requires 4 RCPs operating prior to the withdrawal of control banks when the reactor is subcritical with Tavg greater than 350°F (Mode 3). ITS LCO 3.4.5.a requires 2 RCPs operating whenever the rod control system is capable of performing withdrawal of any control rods when in Mode 3. (ITS LCO 3.4.4 requires 4 RCPs in operation in Modes 1 and 2 as would occur when withdrawing control banks to approach criticality.)

   This change, reducing the number of RCPs that must be in operation when the potential for a rod withdrawal error exists, will not result in a significant increase in the probability of an accident previously evaluated because the number of reactor coolant pumps in operation does not affect the initiators of any analyzed events. This change will not result in a significant increase in the consequences of an accident previously evaluated because both CTS 3.1.A.1.b.2 and ITS LCO 3.4.5.a are intended to ensure that the number of RCPs assumed to be operating in the analysis of an uncontrolled control rod withdrawal from subcritical condition are operating when conditions exist such that an uncontrolled control rod withdrawal could occur. This change is acceptable because the accident analysis for uncontrolled rod withdrawal from a subcritical condition is valid when two or more reactor coolant pumps are in operation.

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

   The proposed changes will not involve any physical changes to plant systems, structures, or components (SSC). The changes in normal Plant operation are consistent with the current safety analysis assumptions because the way reactor coolant pumps are operated is not changed and the accident analysis for uncontrolled rod withdrawal from a subcritical condition is valid when two or more reactor coolant pumps are in operation. Therefore, these changes will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   This change does not involve a significant reduction in a margin of safety because both CTS 3.1.A.1.b.2 and ITS LCO 3.4.5.a are intended to ensure that the number of RCPs assumed to be operating in the analysis of an uncontrolled control rod withdrawal from subcritical condition are operating when conditions exist such that an uncontrolled control rod withdrawal could occur. This change is acceptable because the accident analysis for uncontrolled rod withdrawal from a subcritical condition is valid when two or more reactor coolant pumps are in operation.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.5:
"RCS Loops - MODE 3"

PART 5:

NUREG-1431
Annotated to show differences between
NUREG-1431 and ITS

Status of NUREG 1431 Generic Changes for ITS 3.4.5

This ITS Specification is based on NUREG-1431 Specification No. **3.4.5**
as modified by the following Generic Changes:

OG No.	TSTF No.	Generic Change Description	NRC STATUS	IP3 STATUS	JD No.
WOG-046	**087 R2**	REVISE "RTBS OPEN" & "CRDM DE-ENERGIZED" ACTIONS TO "INCAPABLE OF ROD WITHDRAWAL"	Approved by NRC	Not Incorporated	**N/A**
WOG-063	**153 R0**	CLARIFY EXCEPTION NOTES TO BE CONSISTENT WITH THE REQUIREMENT	Approved by NRC	Incorporated	**T.1**

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.5 RCS Loops—MODE 3

<CTS>

<3.1.A.1.b>
<DOC M.1>
<DOC L.1>
<DOC M.5>

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.

<3.1.A.1.b.1>
<3.1.A.1.a>
<DOC M.3>

NOTE

All reactor coolant pumps may be de-energized for ≤ 1 hour per 8 hour period provided: not be in operation T.1

a. No operations are permitted that would cause reduction of the RCS boron concentration; and

b. Core outlet temperature is maintained at least ≥ 10°F below saturation temperature. PA.1

<3.1.A.1.b.1>
<3.1.A.1.b.2>

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

<DOC M.2>

<DOC M.2>

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One required RCS loop not in operation, and reactor trip breakers closed and Rod Control System capable of rod withdrawal. <DOC M.2>	C.1 Restore required RCS loop to operation.	1 hour
	OR	
	C.2 De-energize all control rod drive mechanisms (CRDMs).	1 hour
D. ~~[Two]~~ Required RCS loops inoperable.	D.1 De-energize all CRDMs.	Immediately (PA.1)
OR	AND	
No RCS loop in operation. <DOC M.2>	D.2 Suspend all operations involving a reduction of RCS boron concentration.	Immediately
	AND	
	D.3 Initiate action to restore one RCS loop to OPERABLE status and operation. (PA.1)	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.4.5.1 Verify required RCS loops are in operation. <DOC M.4>	12 hours

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.5.2	Verify steam generator secondary side water levels ~~are ≥ 17% for~~ actual required RCS loop~~s~~.	12 hours
SR 3.4.5.3	Verify correct breaker alignment and indicated power are available to the required pump that is not in operation.	7 days

<DOC M.4>

Insert: 3.4-10-01

<DOC M.4>

DB.2

INSERT: 3.4-10-01

is ≥ 71% (wide range equivalent) for each DB.2

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.5 RCS Loops—MODE 3

BASES

BACKGROUND

In MODE 3, the primary function of the reactor coolant is removal of decay heat and transfer of this heat, via the steam generator (SG), to the secondary plant fluid. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

The reactor coolant is circulated through ~~[four]~~ RCS loops, connected in parallel to the reactor vessel, each containing an SG, a reactor coolant pump (RCP), ~~and~~ appropriate flow, pressure, ~~level~~, and temperature instrumentation for control, protection, and indication. The reactor vessel contains the ~~CRD~~ fuel. The SGs provide the heat sink. The RCPs circulate the water through the reactor vessel and SGs at a sufficient rate to ensure proper heat transfer and prevent fuel damage.

In MODE 3, RCPs are used to provide forced circulation for heat removal during heatup and cooldown. The MODE 3 decay heat removal requirements are low enough that a single RCS loop with one RCP running is sufficient to remove core decay heat. However, ~~[two]~~ RCS loops are required to be OPERABLE to ensure redundant capability for decay heat removal.

APPLICABLE SAFETY ANALYSES

Whenever the reactor trip breakers (RTBs) are in the closed position and the control rod drive mechanisms (CRDMs) are energized, an inadvertent rod withdrawal from subcritical, resulting in a power excursion, is possible. Such a transient could be caused by a malfunction of the rod control system. In addition, the possibility of a power excursion due to the ejection of an inserted control rod is possible with the breakers closed or open. Such a transient could be caused by the mechanical failure of a CRDM.

Therefore, in MODE 3 with RTBs in the closed position and Rod Control System capable of rod withdrawal, ~~accidental~~ control rod withdrawal from subcritical is postulated and requires at least ~~[two]~~ RCS loops to be OPERABLE and in operation to ensure that the accident analyses limits are

(continued)

INSERT: B 3.4-21-01

DB.1

Calculations have shown that reactor decay heat equivalent to 10% rated power can be removed via the steam generators with natural circulation. This analysis assumed conservative flow resistances including steam generator tube plugging and a lock rotor in each loop (Ref. 1).

BASES

APPLICABLE SAFETY ANALYSES (continued)

met. For those conditions when the Rod Control System is not capable of rod withdrawal, two RCS loops are required to be OPERABLE, but only one RCS loop is required to be in operation to be consistent with MODE 3 accident analyses.

Failure to provide decay heat removal may result in challenges to a fission product barrier. The RCS loops are part of the primary success path that functions or actuates to prevent or mitigate a Design Basis Accident or transient that either assumes the failure of, or presents a challenge to, the integrity of a fission product barrier.

RCS Loops—MODE 3 satisfy Criterion 3 of ~~the NRC Policy Statement~~. 10 CFR 50.36

LCO

The purpose of this LCO is to require that at least ~~[two]~~ RCS loops be OPERABLE. In MODE 3 with the RTBs in the closed position and Rod Control System capable of rod withdrawal, ~~[two]~~ RCS loops must be in operation. ~~[Two]~~ RCS loops are required to be in operation in MODE 3 with RTBs closed and Rod Control System capable of rod withdrawal due to the postulation of a power excursion because of an ~~inadvertent control~~ uncontrolled rod withdrawal. The required number of RCS loops in operation ensures that the Safety Limit criteria will be met for all of the postulated accidents. DB.1

With the RTBs in the open position, or the CRDMs de-energized, the Rod Control System is not capable of rod withdrawal; therefore, only one RCS loop in operation is necessary to ensure removal of decay heat from the core and homogenous boron concentration throughout the RCS. An additional RCS loop is required to be OPERABLE to ensure ~~that safety analyses limits are met~~ redundant decay heat removal capability. PA.1

The Note permits all RCPs to ~~be de-energized~~ not be in operation for ≤ 1 hour per 8 hour period. The purpose of the Note is to ~~perform tests that are designed to validate various accident analyses values. One of these tests is validation of the pump coastdown curve used as input to a number of accident analyses including a loss of flow accident. This test is generally performed in MODE 3 during the initial startup testing program, and as such should only be performed once. If, however, changes are made to the RCS that would cause a change to the flow characteristics of the RCS, the input~~ Insert: B3.4-22-01 T.1 T.1

(continued)

INSERT: B 3.4-22-01

T.1

permit performance of required tests or maintenance that can only be performed with all reactor coolant pumps not in operation.

BASES

LCO (continued)

~~values of the coastdown curve must be revalidated by conducting the test again. Another test 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 de-energizing of the pumps in order to perform this test and validate the assumed analysis values. As with the validation of the pump coastdown curve, this test should be performed only once unless the flow characteristics of the RCS are changed. The 1 hour time period specified is adequate to perform the desired tests and operating experience has shown that boron stratification is not a problem during this short period with no forced flow.~~

stopping

T.1

PA.1

is acceptable because

Utilization of the Note is permitted provided the following conditions are met, along with any other conditions imposed by ~~initial startup~~ test procedures: or maintenance

PA.1

a. No operations are permitted that would dilute the RCS boron concentration, thereby maintaining the margin to criticality. Boron reduction is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation; and

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.

An OPERABLE RCS loop consists of one OPERABLE RCP and one OPERABLE SG in accordance with the Steam Generator Tube Surveillance Program, which has the minimum water level specified in SR 3.4.5.2. An RCP is OPERABLE if it is capable of being powered and is able to provide forced flow if required.

APPLICABILITY

In MODE 3, this LCO ensures forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. The most stringent condition of the LCO, that is, two RCS loops OPERABLE and two RCS loops in operation, applies to MODE 3 with RTBs in the

(continued)

BASES

APPLICABILITY (continued)

closed position. The least stringent condition, that is, two RCS loops OPERABLE and one RCS loop in operation, applies to MODE 3 with the RTBs open.

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops—MODES 1 and 2";
LCO 3.4.6, "RCS Loops—MODE 4";
LCO 3.4.7, "RCS Loops—MODE 5, Loops Filled";
LCO 3.4.8, "RCS Loops—MODE 5, Loops Not Filled";
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation—High Water Level" (MODE 6); and
LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation—Low Water Level" (MODE 6).

ACTIONS

A.1

If one required RCS loop is inoperable, redundancy for heat removal is lost. The Required Action is restoration of the required RCS loop to OPERABLE status within the Completion Time of 72 hours. This time allowance is a justified period to be without the redundant, nonoperating loop because a single loop in operation has a heat transfer capability greater than that needed to remove the decay heat produced in the reactor core and because of the low probability of a failure in the remaining loop occurring during this period.

B.1

If restoration is not possible within 72 hours, the unit must be brought to MODE 4. In MODE 4, the unit may be placed on the Residual Heat Removal System. The additional Completion Time of 12 hours is compatible with required operations to achieve cooldown and depressurization from the existing plant conditions in an orderly manner and without challenging plant systems.

C.1 and C.2

If the required RCS loop is not in operation, and the RTBs are closed and Rod Control System capable of rod withdrawal,

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

the Required Action is either to restore the required RCS loop to operation or to de-energize all CRDMs by opening the RTBs or de-energizing the motor generator (MG) sets. When the RTBs are in the closed position and Rod Control System are capable of rod withdrawal, it is postulated that a power excursion could occur in the event of an inadvertent control rod withdrawal. This mandates having the heat transfer capacity of two RCS loops in operation. If only one loop is in operation, the RTBs must be opened. The Completion Times of 1 hour to restore the required RCS loop to operation or de-energize all CRDMs is adequate to perform these operations in an orderly manner without exposing the unit to risk for an undue time period.

PA.1

D.1, D.2, and D.3

If ~~two~~ required RCS loops are inoperable or no RCS loop is in operation, except as during conditions permitted by the Note in the LCO section, all CRDMs must be de-energized by opening the RTBs or de-energizing the MG sets. All operations involving a reduction of RCS boron concentration must be suspended, and action to restore one of the RCS loops to OPERABLE status and operation must be initiated. Boron dilution requires forced circulation for proper mixing, and opening the RTBs or de-energizing the MG sets removes the possibility of an inadvertent rod withdrawal. The immediate Completion Time reflects the importance of maintaining operation for forced circulation heat removal. The action to restore must be continued until one loop is restored to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.5.1

This SR requires verification every 12 hours that the required loops are in operation. Verification can be based on includes flow rate, ~~temperature,~~ or and pump status monitoring, which ~~help~~ ensure that forced flow is providing heat removal. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RCS loop performance.

PA.1

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.5.2

SR 3.4.5.2 requires verification of SG OPERABILITY. SG OPERABILITY is verified by ensuring that the secondary side narrow range water level is ≥ [17]% for required RCS loops. If the SG secondary side narrow range water level is < [17]%, the tubes may become uncovered and the associated loop may not be capable of providing the heat sink for removal of the decay heat. The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to a loss of SG level.

actual

DB.2

Insert: B 3.4-26-01

71

actual

SR 3.4.5.3

Verification that the required RCPs are OPERABLE ~~ensures that safety analyses limits are met. The requirement also~~ ensures that an additional RCP can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power availability to the required RCPs.

REFERENCES None.

INSERT: B 3.4-26-01

is ≥ 71% (wide range equivalent) for each required loop. Depending on plant conditions, either wide range or narrow range SG level instruments may be used to verify this SR is met. Operators may be required to adjust the indicated level to compensate for the effects of SG temperature.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.5:
"RCS Loops - MODE 3"

PART 6:

Justification of Differences between

NUREG-1431 and IP3 ITS

JUSTIFICATION OF DIFFERENCES FROM NUREG-1431
ITS SECTION 3.4.5 - RCS Loops - MODE 3

RETENTION OF EXISTING REQUIREMENT (CURRENT LICENSING BASIS)

None

PLANT-SPECIFIC WORDING PREFERENCE OR MINOR EDITORIAL IMPROVEMENT

PA.1 Corrected typographical error or made a minor editorial improvement to improve clarity and ensure requirements are fully understood and consistently applied. There are no technical changes to requirements as specified in NUREG 1431, Rev. 1; therefore, this change is not a significant or generic deviation from NUREG 1431, Rev 1.

PLANT-SPECIFIC DIFFERENCE IN THE DESIGN OR DESIGN BASIS

DB.1 Design or implementation details are incorporated or revised as necessary to more precisely describe IP3 current design or practice. These changes are intended to describe the design, improve clarity, or ensure requirements are fully understood and consistently applied. Unless identified and described blow, these changes are self-explanatory. A detailed description of the design, accident analysis assumptions, and Operability requirements are incorporated into the IP3 ITS Bases. These changes maintain the IP3 current licensing basis except as identified and justified in the CTS/ITS discussion of changes.

DB.2 IP3 clarifies the wording the SR that requires periodic verification of SG water level to ensure that the acceptance criteria clearly require that SG tubes are covered. This change is needed because IP3 SG wide range and narrow range level instruments use a different starting reference. Additionally, depending on plant conditions, either wide range or narrow range SG level instruments may be the only instruments available to verify this SR is met. Finally, operators may be required to adjust the indicated level to compensate for the effects of SG temperature because the indicated level may be affected by the SG temperature relative to the temperature at which level the level calibration was performed. This change has no significant adverse impact on safety.

JUSTIFICATION OF DIFFERENCES FROM NUREG-1431
ITS SECTION 3.4.5 - RCS Loops - MODE 3

DIFFERENCE BASED ON A GENERIC CHANGE TRAVELER FOR NUREG-1431

T.1 This change incorporates Generic Change TSTF-153, Rev.0 (WOG-63) which rewords notes taking exception to LCO requirements to be consistent with the wording of the requirement. Specifically, the LCO contains a Note taking exception to the LCO requirement for pumps to "be in operation" but states the exception as "may be de-energized." Therefore, each Note is revised to provide wording consistent with the requirement being excepted.

DIFFERENCE FOR ANY REASON OTHER THAN ABOVE

None

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.6:
"RCS Loops - MODE 4"

PART 1:

Indian Point 3
Improved Technical Specifications and Bases

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 not be in operation for ≤ 1 hour per 8 hour period provided:

   a. No operations are permitted that would cause reduction of the RCS boron concentration; and

   b. Core outlet temperature is maintained ≥ 10°F below saturation temperature.

2. No RCP shall be started with any RCS cold leg temperature less than the LTOP arming temperature unless the requirements of LCO 3.4.12, Low Temperature Overpressure Protection (LTOP), are met.

APPLICABILITY: MODE 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required RCS loop inoperable. AND Two RHR loops inoperable.	A.1 Initiate action to restore a second loop to OPERABLE status.	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. One required RHR loop inoperable. AND Two required RCS loops inoperable.	B.1	Be in MODE 5.	24 hours
C. Required RCS or RHR loops inoperable. OR No RCS or RHR loop in operation.	C.1	Suspend all operations involving a reduction of RCS boron concentration.	Immediately
	AND		
	C.2	Initiate action to restore one loop to OPERABLE status and in operation.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.6.1	Verify one RHR or RCS loop is in operation.	12 hours
SR 3.4.6.2	Verify SG secondary side water actual level is ≥ 71% (wide range equivalent) for each required RCS loop.	12 hours
SR 3.4.6.3	Verify correct breaker alignment and indicated power are available to the required pump that is not in operation.	7 days

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.6 RCS Loops – MODE 4

BASES

BACKGROUND

In MODE 4, the primary function of the reactor coolant is the removal of decay heat and the transfer of this heat to either the steam generator (SG) secondary side coolant or the component cooling water via the residual heat removal (RHR) heat exchangers. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

The reactor coolant is circulated through four RCS loops connected in parallel to the reactor vessel, each loop containing a SG and a reactor coolant pump (RCP). Appropriate flow, pressure, and temperature instrumentation are available for control, protection, and indication. The RCPs and RHR pumps circulate the coolant through the reactor vessel and SGs at a sufficient rate to ensure proper heat transfer and to prevent boric acid stratification.

Each RHR loop consists of one RHR pump and one RHR heat exchanger as well as associated piping and valves to transfer heat between the RHR heat exchanger and the core. Although either RHR heat exchanger may be credited for either RHR loop, one RHR heat exchanger must be OPERABLE for each OPERABLE RHR loop.

In MODE 4, either RCPs or RHR loops can be used to provide forced circulation. The intent of this LCO is to provide forced flow from at least one RCP or one RHR loop for decay heat removal and transport. The flow provided by one RCP loop or RHR loop is adequate for decay heat removal. The other intent of this LCO is to require that two paths be available to provide redundancy for decay heat removal.

When the boron concentration of the RCS is reduced, the process should be uniform to prevent sudden reactivity changes. Mixing of the reactor coolant will be sufficient to maintain a uniform boron concentration if at least one reactor coolant pump or one residual heat removal pump is running while boron concentration is being changed. The residual heat removal pump will circulate the primary system volume in approximately one half hour. Boron

BASES

BACKGROUND (Continued)

concentration in the pressurizer is not a concern because of the low pressurizer volume and because the pressurizer boron concentration will be higher than that of the rest of the reactor coolant.

Calculations have shown that reactor decay heat equivalent to 10% rated power can be removed via the steam generators with natural circulation. This analysis assumed conservative flow resistances including steam generator tube plugging and a lock rotor in each loop (Ref. 1).

APPLICABLE SAFETY ANALYSES

In MODE 4, RCS circulation is considered in the determination of the time available for mitigation of the accidental boron dilution event. The RCS and RHR loops provide this circulation.

RCS Loops – MODE 4 satisfy Criterion 4 of 10 CFR 50.36.

LCO

The purpose of this LCO is to require that at least two loops be OPERABLE in MODE 4 and that one of these loops be in operation. The LCO allows the two loops that are required to be OPERABLE to consist of any combination of RCS loops and RHR loops. Any one loop in operation provides enough 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 not be in operation for ≤ 1 hour per 8 hour period. The purpose of the Note is to permit performance of required tests or maintenance that can only be performed with no forced circulation. 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.

BASES

LCO (continued)

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, therefore maintaining the margin to criticality. Boron reduction is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation; and

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 requirments of LCO 3.4.12, Low Temperature Overpressure Protection (LTOP), must be met before the start of an RCP with any RCS cold leg temperature less than or equal to the LTOP arming temperature. This restraint is to prevent a low temperature overpressure event due to a thermal transient when an RCP is started.

An OPERABLE RCS loop comprises an OPERABLE RCP and an OPERABLE SG in accordance with the Steam Generator Tube Surveillance Program, which has the minimum water level specified in SR 3.4.6.2.

Similarly for the RHR System, an OPERABLE RHR loop comprises an OPERABLE RHR pump capable of providing forced flow to an OPERABLE RHR heat exchanger. RCPs and RHR pumps are OPERABLE if they are capable of being powered and are able to provide forced flow if required.

APPLICABILITY

In MODE 4, this LCO ensures forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. One loop of either RCS or RHR provides sufficient circulation for these purposes. However, two loops consisting of any combination of RCS and RHR loops are required to be OPERABLE to meet single failure considerations.

BASES

APPLICABILITY (continued)

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 3.4.7, "RCS Loops – MODE 5, Loops Filled";
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

A.1

If one required RCS loop is inoperable and two RHR loops are inoperable, redundancy for heat removal is lost. Action must be initiated to restore a second RCS or RHR loop to OPERABLE status. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

B.1

If one required RHR loop is OPERABLE and in operation and there are no RCS loops OPERABLE, an inoperable RCS or RHR loop must be restored to OPERABLE status to provide a redundant means for decay heat removal.

If the parameters that are outside the limits cannot be restored, the unit must be brought to MODE 5 within 24 hours. Bringing the unit to MODE 5 is a conservative action with regard to decay heat removal. With only one RHR loop OPERABLE, redundancy for decay heat removal is lost and, in the event of a loss of the only OPERABLE RHR loop, it would be safer to initiate that loss from MODE 5 (≤ 200°F) rather than MODE 4 (200 to 300°F). The Completion Time of 24 hours is a reasonable time, based on operating experience, to reach MODE 5 from MODE 4 in an orderly manner and without challenging plant systems.

BASES

ACTIONS (continued)

C.1 and C.2

If no loop is OPERABLE or in operation, except during conditions permitted by Note 1 in the LCO section, all operations involving a reduction of RCS boron concentration must be suspended and action to restore one RCS or RHR loop to OPERABLE status and in operation must be initiated. Boron dilution requires forced circulation for proper mixing, and the margin to criticality must not be reduced in this type of operation. The immediate Completion Times reflect the importance of maintaining operation for decay heat removal. The action to restore must be continued until one loop is restored to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.6.1

This SR requires verification every 12 hours that one RCS or RHR loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RCS and RHR loop performance.

SR 3.4.6.2

SR 3.4.6.2 requires verification of SG OPERABILITY. SG OPERABILITY is verified by ensuring that the actual secondary side water level is ≥ 71% (wide range equivalent) for each required loop. Depending on plant conditions, either wide range or narrow range SG level instruments may be used to verify this SR is met. Operators may be required to adjust the indicated level to compensate for the effects of SG temperature. If the SG secondary side actual water level is < 71%, the tubes may become uncovered and the associated loop may not be capable of providing the heat sink necessary for removal of decay heat. The 12 hour

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.6.2 (continued)

Frequency is considered adequate in view of other indications available in the control room to alert the operator to the loss of SG level.

SR 3.4.6.3

Verification that the required pump is OPERABLE ensures that an additional RCS or RHR pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the required pump and associated support systems. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES

1. FSAR Chapter 14.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.6:
"RCS Loops - MODE 4"

PART 2:

CURRENT TECHNICAL SPECIFICATION PAGES

Annotated to show differences between CTS and ITS

CTS pages and associated TSCRs annotated for this ITS Specification :

CTS Page No.	Effective Amendment	Annotated Amendment	TSCR No.	TSCR Description	ITS Status of TSCR
3.1-1	121	121	No TSCRs	No TSCRs for this Page	N/A
3.1-2	179	179	No TSCRs	No TSCRs for this Page	N/A
3.1-3	179	179	No TSCRs	No TSCRs for this Page	N/A
3.1-7	121	121	No TSCRs	No TSCRs for this Page	N/A
3.3-5	53	53	No TSCRs	No TSCRs for this Page	N/A

A.1

3. LIMITING CONDITIONS FOR OPERATION

SEE ITS 3.0

For the cases where no exception time is specified for inoperable components, this time is assumed to be zero.

3.1 REACTOR COOLANT SYSTEM

A.2

~~Applicability~~

~~Applies to the operating status of the Reactor Coolant System: operational components; heatup; cooldown; criticality; activity; chemistry and leakage.~~

~~Objective~~

~~To specify those limiting conditions for operation of the Reactor Coolant System which must be met to ensure safe reactor operation.~~

Specification

~~A.~~ OPERATIONAL COMPONENTS

~~1.~~ Coolant Pumps

LCO 3.4.6, Note 1.a
Req. Act C.1

a. When a reduction is made in the boron concentration of the reactor coolant, at least one reactor coolant pump or one residual heat removal pump (connected to the Reactor Coolant System) shall be in operation.

SEE ITS 3.4.5

b. (1) When the reactor coolant system T_{avg} is greater than 350°F and electrical power is available to the reactor coolant pumps, and as permitted during special plant evolutions, at least one reactor coolant pump shall be in operation. All reactor coolant pumps may be de-energized for up to 1 hour provided no operations are permitted that would cause dilution of the reactor coolant system boron concentration, and core outlet temperature is maintained at least 10°F below saturation temperature.

(2) When the reactor is subcritical and reactor coolant system T_{avg} is greater than 350°F, control bank withdrawal shall be prohibited unless four reactor coolant pumps are operating.

LCO 3.4.6, Applicability

LCO 3.4.6

LCO 3.4.6, Note 1

When the reactor coolant system T_{avg} is greater than 200°F and less than 350°F, and as permitted during special plant evolutions, at least one reactor coolant pump or one residual heat removal pump (connected to the Reactor Coolant System) shall be in operation. All reactor coolant pumps may be de-energized with RHR not in service for up to 1 hour provided no operations are permitted that would cause dilution of the reactor coolant system boron concentration, and core outlet temperature is maintained at least 10°F below saturation temperature.

Mode 4

A.3

per 8 hour period

M.1

SEE ITS 3.4.7 ITS 3.4.8

d. When the reactor coolant system T_{avg} is less than 200°F, but not in the refueling operation condition, and as permitted during special plant evolutions, at least one residual heat removal pump (connected to the Reactor Coolant System) shall be in operation. This RHR pump may be out of service for up to 1 hour provided no operations are permitted that would cause dilution of the reactor coolant system boron concentration, and core outlet temperature is maintained at least 10°F below saturation temperature.

SEE ITS 3.4.4 ITS 3.4.17

e. When the reactor is critical and above 2% rated power, except for natural circulation tests, at least two reactor coolant pumps shall be in operation.

f. The reactor shall not be operated at power levels above 10% rated power with less than four (4) reactor coolant loops in operation.

g. If the requirements of 3.1.A.1.e and 3.1.A.1.f above cannot be satisfied, the reactor shall be brought to the hot shutdown condition within 1 hour.

SEE ITS 3.4.12

h. A reactor coolant pump (RCP) may not be started (or jogged) when the RCS cold leg temperature (T_{cold}) is at or below 319°F, unless RCS make up is not in excess of RCS losses, and one of the following requirements is met:

(1) The OPS is operable, steam generator pressure is not decreasing, and the temperature of each steam generator is less than or equal to the coldest T_{cold};

Or

(2) The OPS is operable, the temperature of the hottest steam generator exceeds the coldest T_{cold} by no more than 64°F, pressurizer level is at or below 73 percent, and T_{cold} is as per Figure 3.1.A-1;

Or

(3) With OPS inoperable, steam generator pressure is not decreasing, the temperature of each steam generator is less than or equal to the coldest T_{cold}, pressurizer level is at or below 73 percent, and the RCS pressure does not exceed that given by Fig. 3.1.A-2. The pressurizer level must be further restricted per Figures 3.1.A-5 and 3.1.A-6 if operation below 319°F exceeds 8 hours.

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A.1

Basis

When the boron concentration of the Reactor Coolant System is to be reduced the process must be uniform to prevent sudden reactivity changes in the reactor. Mixing of the reactor coolant will be sufficient to maintain a uniform boron concentration if at least one reactor coolant pump or one residual heat removal pump is running while the change is taking place. The residual heat removal pump will circulate the primary system volume in approximately one half hour. The pressurizer is of no concern because of the low pressurizer volume and because the pressurizer boron concentration will be higher than that of the rest of the reactor coolant. A.1

Heat transfer analyses show that reactor heat equivalent to 10% of rated power (P-7) can be removed with natural circulation only (1); hence, the requirement for one operating RCP above 350°F and two operating RCP's above 2% rated power provides a substantial safety factor. In addition, a single RCP or RHR pump (connected to the RCS) provides sufficient heat removal capability for removing decay heat.

The restriction on control bank withdrawal with less than four reactor coolant pumps operating when the reactor is subcritical and RCS T_{avg} is greater than 350°F is necessary to conform with the assumptions used in the transient analyses for the uncontrolled control rod withdrawal event from subcritical condition. The FSAR safety analysis for uncontrolled control rod assembly withdrawal from a subcritical condition assumes all four reactor coolant pumps to be operating within the temperature range of concern. Using this assumption the DNB design basis is satisfied for the combination of the two banks of the maximum combined worth withdrawn at maximum speed. Since there is no mechanism by which the control rods can be automatically withdrawn due to a control system error when T_{avg} is between 350°F and the no-load temperature, such an event can only be initiated as a result of human error during rod manipulation. Prohibiting control bank withdrawal with less than four RCPs operating provides assurance that the plant is operated within the accident analysis assumptions.

The reactor shall not be operated at power levels above 10% rated power with less than four (4) reactor coolant loops in operation until safety analyses for less than four loop operation have been submitted by the licensee and approval for less than four loop operation at power levels above 10% rated power has been granted by the Commission. (See license condition 2.C. (3))

Each of the pressurizer code safety valves is designed to relieve 420,000 lbs. per hr. of saturated steam at the valve set point.

If no residual heat were removed by the Residual Heat Removal System the amount of steam which could be generated at safety valve relief pressure would be less than half the capacity of a single valve. One valve therefore provides adequate protection for overpressurization.

The combined capacity of the three pressurizer safety valves is greater than the maximum surge rate resulting from complete loss of load (2) without a direct reactor trip or any other control.

5. If the Safety Injection and Residual Heat Removal Systems are not restored to meet the requirements of 3.3.A.3 within the time periods specified in 3.3.A.4; then:

SEE ITS 3.5.1 ITS 3.5.2 ITS 3.5.3 ITS 3.5.4

a. If the reactor is critical, it shall be in the hot shutdown condition within four hours and the cold shutdown condition within the following 24 hours.

b. If the reactor is subcritical, the reactor coolant system temperature and pressure shall not be increased more than 25°F and 100 psi, respectively, over existing values. If the requirements of 3.3.A.3 are not satisfied within an additional 48 hours, the reactor shall be brought to the cold shutdown condition using normal operating procedures. The shutdown shall start no later than the end of the 48 hour period.

LCO 3.4.6 Applicability

6. When the reactor coolant system T_{avg} is greater than 200°F and less than 350°F, the following decay heat removal requirements shall be met: (Mode 4)

LCO 3.4.6

a. Two residual heat removal pumps together with their associated heat exchangers, piping, and valves shall be operable, (loop) (A.3)

OR

b. A minimum of one residual heat removal pump and heat exchanger and a minimum of one reactor coolant pump and steam generator together with their associated piping and valves, shall be operable, (LA.1)

OR

c. A minimum of two reactor coolant pumps and two steam generators, together with their associated piping and valves, shall be operable, (loop)

OR

Req. Act A.1 Req. Act. B.1 Req. Act C.1, C.2

~~d.~~ With less than the above operable, initiate corrective action to return the required equipment to an operable status as soon as possible and suspend any operations which would reduce the boron concentration of the reactor coolant system. Otherwise, if sufficient equipment is available, be in cold shutdown within 20 hours. (24) (A.6) (Mode 5) (L.1)

7. When the reactor coolant T_{avg} is less than 200°F, but not in the refueling operation condition, two residual heat removal pumps, together with their associated heat exchangers, piping and valves, shall be operable.

SEE ITS 3.4.7

a. With less than the above operable, initiate corrective action to return the required equipment to an operable status as soon as possible and suspend any operations which would reduce the boron concentration of the reactor coolant system.

b. The above requirements may be suspended during maintenance, modifications, testing, inspection or repair provided that:

1) an alternate means of decay heat removal is available and return of the system within sufficient time to prevent exceeding cold shutdown requirements is assured;

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.6:
"RCS Loops - MODE 4"

PART 3:

DISCUSSION OF CHANGES

Differences between CTS and ITS

DISCUSSION OF CHANGES
ITS SECTION 3.4.6 - RCS Loops - MODE 4

ADMINISTRATIVE

A.1 In the conversion of the Indian Point Unit 3 Current Technical Specifications (CTS) to the plant specific Improved Technical Specifications (ITS) certain wording preferences or conventions are adopted which do not result in technical changes (either actual or interpretational). Additionally, editorial changes, reformatting, and revised numbering are adopted to make ITS consistent with the conventions in NUREG-1431, Standard Technical Specifications, Westinghouse Plants, Rev. 1, i.e., the improved Standard Technical Specifications.

The CTS Bases are deleted and replaced with comprehensive ITS Bases that are designed to support interpretation and implementation of the associated Technical Specifications. The Bases explain, clarify, and document the reasons (i.e., bases) for the associated Technical Specifications, and reflect the IP3 plant specific design, analyses, and licensing basis. In accordance with 10 CFR 50.36(a), the ITS Bases are included with the proposed ITS conversion application; however, deletion of the CTS Bases and the adoption of the ITS Bases is an administrative change with no impact on safety because neither are required by 10 CFR 50.36, and neither define or impose any specific requirements.

A.2 CTS Limiting Conditions for Operation (LCOs) and Surveillance Requirements (SRs) include statements of the objective and the applicability. The CTS statements of objective and applicability are deleted because these statements do not establish any requirements and do not provide any guidance for the application of CTS requirements. Therefore, deletion of these statements has no significant adverse impact on safety.

A.3 The combination of CTS 3.1.A.1.c and CTS 3.3.A.6 establish requirements for decay heat removal when the reactor coolant system Tavg is greater than 200°F and less than 350°F (Mode 4). CTS 3.1.A.1.c requires that at least one reactor coolant pump or one residual heat removal pump is operating. CTS 3.3.A.6 requires that two pathways for decay heat

removal be Operable with the two pathways consisting of any combination of residual heat removal pumps or reactor coolant pumps. ITS LCO 3.4.6 establishes requirements consistent with the combination of the two existing CTS requirements. The reorganization of requirements is an administrative change with no adverse impact on safety.

A.4 CTS 3.1.A.1.c specifies that CTS requirements for decay heat removal may be modified "as permitted during special plant evolutions." ITS 3.4.6 deletes this exception to the LCO applicability because it is ambiguous and does not provide any clearly identifiable requirements or allowances. Therefore, deletion of this statement results in no change to the existing requirements. Therefore, this is an administrative change with no impact on safety.

A.5 CTS 3.1.A.1.h establishes requirements for starting reactor coolant pumps (RCPs) when reactor coolant system temperature is below the low temperature overpressure protection (LTOP) arming temperature. ITS LCO 3.4.12, Low Temperature Overpressure Protection (LTOP), includes surveillance requirements that maintain these allowances and requirements (See ITS 3.4.12). ITS LCO 3.4.6, Note 2, is added to ensure that ITS LCO 3.4.12 requirements are met prior to starting RCPs when in Mode 4. The addition of ITS LCO 3.4.6, Note 2, is an administrative change with no adverse impact on safety because it is a cross reference between ITS LCO 3.4.6 and ITS LCO 3.4.12 requirements.

A.6 CTS 3.3.A.6.d specifies that with less than the required minimum combination of RCPs and RHR operable, initiate corrective action to return the required equipment to an operable status as soon as possible. Otherwise, if sufficient equipment is available, be in cold shutdown within a specified time (See ITS 3.4.6, DOC L.1).

ITS LCO 3.4.6, Conditions A, B and C, establish the same requirements in a more prescriptive manner by differentiating between conditions where sufficient equipment remains available to cooldown to Mode 5 and situations where cooldown to Mode 5 may be prevented by inoperable and

non-functioning equipment. This is an administrative change with no impact on safety because reasonable interpretation of CTS 3.3.A.6.d would result in the same Required Actions as are specified for ITS LCO 3.4.6, Conditions A, B and C.

MORE RESTRICTIVE

M.1 CTS 3.1.A.1.c allows all reactor coolant pumps to be de-energized for up to 1 hour in Mode 4 even when RHR is not in service provided that: a) no operations are permitted that would cause dilution of the reactor coolant system boron concentration; and, b) core outlet temperature is maintained at least 10°F below saturation temperature.

ITS 3.4.6, Note 1, maintains the same allowance; however, ITS 3.4.6 limits the use of this allowance to once in any 8 hour period. This change is needed to ensure that the intent of CTS 3.1.A.1.c (forced circulation in Mode 4) is met and to eliminate any ambiguity regarding the application of the allowance that may be needed to perform required maintenance or testing in Mode 4. This more restrictive change is acceptable because it does not introduce any operation which is un-analyzed while ensuring the intent of LCO 3.4.6, to maintain forced flow in the reactor when in Mode 4, is met. Therefore, this change has no adverse impact on safety.

M.2 CTS 3.1.A.1.c and CTS 3.3.A.6 establish requirements for the minimum number of RCPs and/or RHR pumps that must be Operable and/or operating in Mode 4; however, no surveillance requirements are established to verify that these requirements are met. ITS LCO 3.4.6 requires periodic verification that requirements are met as follows:

ITS SR 3.4.6.1 is added to verify every 12 hours that the minimum number of required RCS or RHR loops are in operation;

ITS SR 3.4.6.2 is added to verify every 12 hours that the minimum steam generator secondary side water levels are acceptable; and,

ITS SR 3.4.6.3 is added to verify every 7 days that the breaker alignment and indicated power are available to the required pump that is not in operation.

This more restrictive change is acceptable because it does not introduce any operation which is un-analyzed while requiring periodic verification that each RCS loop is operating and/or Operable as required by the LCO. Therefore, this change has no adverse impact on safety.

LESS RESTRICTIVE

L.1 CTS 3.3.A.6.d requires placing the plant in cold shutdown (Mode 5) within 20 hours if fewer than the required minimum number of RCPs and/or RHR pumps are operable and if sufficient equipment is available to perform the plant cooldown. Under the same conditions, ITS LCO 3.4.6, Condition B, allows 24 hours to place the plant in Mode 5. This change is acceptable because placing the plant in Mode 5 when an RHR loop capable of decay heat removal is still Operable and in operation is a conservative action because in Mode 5 appropriate actions are available even if the remaining RHR loop fails. Therefore, this change has no significant impact on safety.

REMOVED DETAIL

LA.1 CTS 3.3.A.6 establishes requirements for decay heat removal capability using reactor coolant pumps and/or RHR pumps in Mode 4 that includes a listing of the principal components in the decay heat removal loop such as heat exchangers, piping and valves. ITS LCO 3.4.6 establishes requirements for either reactor coolant system loops or residual heat removal system loops. The details about what constitutes an operable loop are moved to the Bases of ITS 3.4.6.

This change is acceptable because ITS LCO 3.4.6 maintains the Mode 4 requirement to have sufficient decay heat removal capability using either reactor coolant loops or RHR loops; therefore, there is no change to the existing requirements and no change to the level of safety of facility operation.

DISCUSSION OF CHANGES
ITS SECTION 3.4.6 - RCS Loops - MODE 4

This change, which allows the description of the design of the RCS and RHR loops to be maintained in the FSAR and the detailed description of the requirements for Operability of these systems to be maintained in the ITS Bases, is consistent with the approach used in NUREG-1431 for all Limiting Conditions for Operation (LCOs). This approach is acceptable because the requirements of 10 CFR 50.59, Changes, Tests and Experiments, and ITS 5.5.13, Technical Specifications (TS) Bases Control Program, are designed to assure that changes to the FSAR and ITS Bases do not result in changes to the Technical Specification requirements and do not result in significant increases in the probability or consequences of accidents previously evaluated, do not create the possibility of a new or different kind of accident, and do not result in a significant reduction in a margin of safety. Additionally, IP3 programs that implement FSAR changes in accordance with 10 CFR 50.59 and ITS Bases changes in accordance with ITS 5.5.13 require periodic submittal of FSAR and Bases changes to the NRC for review.

This change is a less restrictive administrative change with no impact on safety because no requirements are being deleted from Technical Specifications and an appropriate change control process and an appropriate level of regulatory oversight are maintained for the information being relocated out of the Technical Specifications.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.6:
"RCS Loops - MODE 4"

PART 4:

No Significant Hazards Considerations
for
Changes between CTS and ITS
that are
Less Restrictive

No Significant Hazard Considerations for Changes that are Administrative, More Restrictive, and Removed Details are the same for all Packages. A Copy is included at the end of the Package.

NO SIGNIFICANT HAZARDS EVALUATION
ITS SECTION 3.4.6 - RCS Loops - MODE 5, Loops Filled

LESS RESTRICTIVE
("L.1" Labeled Comments/Discussions)

New York Power Authority has evaluated the proposed Technical Specification change identified as "Less Restrictive" in accordance with the criteria set forth in 10 CFR 50.92, and has determined that the proposed change does not involve a significant hazards consideration. The bases for the determination that the proposed changes do not involve a significant hazards consideration are discussed below.

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

   This change extends the time allowed to perform a plant cooldown to Mode 5 when less than the required redundancy exists for decay heat removal when in Mode 4 from the 20 hours permitted by CTS to the 24 hours permitted by ITS. This change will not result in a significant increase in the probability of an accident previously evaluated because loss of redundant decay heat removal capability is not the precursor of any event. This change will not result in a significant increase in the consequences of an accident previously evaluated because increasing the time that redundant decay heat removal capability is not available from 20 to 24 hours is not significant. Additionally, placing the plant in Mode 5 when an RHR loop capable of decay heat removal is still Operable and in operation is a conservative action because in Mode 5 appropriate actions are available even if the remaining RHR loop fails.

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

   The proposed changes will not involve any physical changes to plant systems, structures, or components (SSC). The changes in normal plant operation are consistent with current safety analysis assumptions because there is no change to the method of decay heat removal in Mode 4. Therefore, these changes will not create the possibility of a new or different accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

This change does not involve a significant reduction in a margin of safety because increasing the time that redundant decay heat removal capability is not available from 20 to 24 hours is not significant. Additionally, placing the plant in Mode 5 when an RHR loop capable of decay heat removal is still Operable and in operation is a conservative action because in Mode 5 appropriate actions are available even if the remaining RHR loop fails.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.6:
"RCS Loops - MODE 4"

PART 5:

NUREG-1431
Annotated to show differences between
NUREG-1431 and ITS

Status of NUREG 1431 Generic Changes for ITS 3.4.6

This ITS Specification is based on NUREG-1431 Specification No. **3.4.6**
as modified by the following Generic Changes:

OG No.	TSTF No.	Generic Change Description	NRC STATUS	IP3 STATUS	JD No.
WOG-063	**153 R0**	CLARIFY EXCEPTION NOTES TO BE CONSISTENT WITH THE REQUIREMENT	Approved by NRC	Incorporated	**T.1**
WOG-067 R1		RELOCATE LTOP ARMING TEMPERATURE TO PTLR	Rejected by TSTF	Not Incorporated	**N/A**
WOG-109		CORRECTION OF LCO 3.4.6 TO INCLUDE ALL POSSIBLE CONDITIONS	TSTF Review	Not Incorporated	**N/A**

3.4 REACTOR COOLANT SYSTEM (RCS)

<CTS> 3.4.6 RCS Loops—MODE 4

<3.1.A.1.c> 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.

<3.3.A.6>
<DOC A.3>

NOTES

<3.1.A.1.a>
<DOC M.1>

1. All reactor coolant pumps (RCPs) and RHR pumps may be ~~de-energized~~ for ≤ 1 hour per 8 hour period provided: (T.1)

   not be in operation

   a. No operations are permitted that would cause reduction of the RCS boron concentration; and

   b. Core outlet temperature is maintained at least (≥) 10°F below saturation temperature. (PA.1)

<3.1.A.1.b>
<DOC A.5>

2. No RCP shall be started with any RCS cold leg temperature ≤ [275]°F ~~unless the secondary side water temperature of each steam generator (SG) is ≤ [50]°F above each of the RCS cold leg temperatures.~~ (DB.3)

   Insert: 3.4-11-01

<3.1.A.1.c>
<3.3.A.6>

APPLICABILITY: MODE 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required RCS loop inoperable. **AND** Two RHR loops inoperable.	A.1 Initiate action to restore a second loop to OPERABLE status.	Immediately

<3.3.A.6.d>
<DOC A.6>

(continued)

INSERT: 3.4-11-01

less than the LTOP arming temperature unless the requirements of LCO 3.4.12, Low Temperature Overpressure Protection (LTOP), are met.

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One required RHR loop inoperable. AND Two required RCS loops inoperable.	B.1 Be in MODE 5.	24 hours
C. Required RCS or RHR loops inoperable. OR No RCS or RHR loop in operation.	C.1 Suspend all operations involving a reduction of RCS boron concentration. AND C.2 Initiate action to restore one loop to OPERABLE status and operation. (in)	Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.6.1	Verify one RHR or RCS loop is in operation.	12 hours
SR 3.4.6.2	Verify SG secondary side water level (actual) ~~is~~ are ≥ [17]% ~~for~~ required RCS loop~~s~~.	12 hours

(continued)

INSERT: 3.4-12-01

is ≥ 71% (wide range equivalent) for each

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.6.3	Verify correct breaker alignment and indicated power are available to the required pump that is not in operation.	7 days

<DOC M.2>

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.6 RCS Loops—MODE 4

BASES

BACKGROUND

In MODE 4, the primary function of the reactor coolant is the removal of decay heat and the transfer of this heat to either the steam generator (SG) secondary side coolant or the component cooling water via the residual heat removal (RHR) heat exchangers. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

The reactor coolant is circulated through ~~[~~four~~]~~ RCS loops connected in parallel to the reactor vessel, each loop containing an SG~~s~~ a reactor coolant pump (RCP), ~~and~~ ~~a~~ appropriate flow, pressure, ~~level,~~ and temperature instrumentation for control, protection, and indication. The RCPs circulate the coolant through the reactor vessel and SGs at a sufficient rate to ensure proper heat transfer and to prevent boric acid stratification.

and

are available

and RHR pumps

Insert: B3.4-27-01

In MODE 4, either RCPs or RHR loops can be used to provide forced circulation. The intent of this LCO is to provide forced flow from at least one RCP or one RHR loop for decay heat removal and transport. The flow provided by one RCP loop or RHR loop is adequate for decay heat removal. The other intent of this LCO is to require that two paths be available to provide redundancy for decay heat removal.

Insert: B3.4-27-02

PA.1

APPLICABLE SAFETY ANALYSES

In MODE 4, RCS circulation is considered in the determination of the time available for mitigation of the accidental boron dilution event. The RCS and RHR loops provide this circulation.

Insert: B3.4-27-03

~~RCS Loops—MODE 4 have been identified in the NRC Policy Statement as important contributors to risk reduction.~~

LCO

The purpose of this LCO is to require that at least two loops be OPERABLE in MODE 4 and that one of these loops be in operation. The LCO allows the two loops that are required to be OPERABLE to consist of any combination of RCS

(continued)

Typical

INSERT: B 3.4-27-01

Each RHR loop consists of one RHR pump and one RHR heat exchanger as well as associated piping and valves to transfer heat between the RHR heat exchanger and the core. Although either RHR heat exchanger may be credited for either RHR loop, one RHR heat exchanger must be OPERABLE for each OPERABLE RHR loop.

INSERT: B 3.4-27-02

When the boron concentration of the RCS is reduced, the process should be uniform to prevent sudden reactivity changes. Mixing of the reactor coolant will be sufficient to maintain a uniform boron concentration if at least one reactor coolant pump or one residual heat removal pump is running while boron concentration is being changed. The residual heat removal pump will circulate the primary system volume in approximately one half hour. Boron concentration in the pressurizer is not a concern because of the low pressurizer volume and because the pressurizer boron concentration will be higher than that of the rest of the reactor coolant.

Calculations have shown that reactor decay heat equivalent to 10% rated power can be removed via the steam generators with natural circulation. This analysis assumed conservative flow resistances including steam generator tube plugging and a locked rotor in each loop (Ref. 1).

INSERT: B 3.4-27-03

satisfy Criterion 4 of 10 CFR 50.36.

BASES

LCO (continued)

loops and RHR loops. Any one loop in operation provides enough 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.

and

Note 1 permits all RCPs or RHR pumps to be de-energized 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 de-energizing 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 adequate to perform the test, and operating experience has shown that boron stratification is not a problem during this short period with no forced flow.

not be in operation

Insert: B3.4-28-01

stopping

acceptable because

Utilization of Note 1 is permitted provided the following conditions are met along with any other conditions imposed by initial startup test procedures:

or maintenance

a. No operations are permitted that would dilute the RCS boron concentration, therefore maintaining the margin to criticality. Boron reduction is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation; and

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.

Insert: B3.8-28-02

Note 2 requires that the secondary side water temperature of each SG be ≤ [50]°F above each of the RCS cold leg temperatures before the start of an RCP with any RCS cold leg temperature ≤ 275°F. This restraint is to prevent a low temperature overpressure event due to a thermal transient when an RCP is started.

less than or equal to the LTOP arming temperature

An OPERABLE RCS loop comprises an OPERABLE RCP and an OPERABLE SG in accordance with the Steam Generator Tube

(continued)

INSERT: B 3.4-28-01

performance of required tests or maintenance that can only be performed with no forced circulation.

INSERT: B 3.4-28-02

the reactor coolant pump starting requirements of LCO 3.4.12, Low Temperature Overpressure Protection (LTOP), must be met

BASES

LCO (continued)

Surveillance Program, which has the minimum water level specified in SR 3.4.6.2.

Similarly for the RHR System, an OPERABLE RHR loop comprises an OPERABLE RHR pump capable of providing forced flow to an OPERABLE RHR heat exchanger. RCPs and RHR pumps are OPERABLE if they are capable of being powered and are able to provide forced flow if required.

APPLICABILITY

In MODE 4, this LCO ensures forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. One loop of either RCS or RHR provides sufficient circulation for these purposes. However, two loops consisting of any combination of RCS and RHR loops are required to be OPERABLE to meet single failure considerations.

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 3.4.7, "RCS Loops—MODE 5, Loops Filled";
LCO 3.4.8, "RCS Loops—MODE 5, Loops Not Filled";
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation—High Water Level" (MODE 6); and
LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation—Low Water Level" (MODE 6).

ACTIONS

A.1

If one required RCS loop is inoperable and two RHR loops are inoperable, redundancy for heat removal is lost. Action must be initiated to restore a second RCS or RHR loop to OPERABLE status. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

B.1

If one required RHR loop is OPERABLE and in operation and there are no RCS loops OPERABLE, an inoperable RCS or RHR

(continued)

BASES

ACTIONS

B.1 (continued)

loop must be restored to OPERABLE status to provide a redundant means for decay heat removal.

If the parameters that are outside the limits cannot be restored, the unit must be brought to MODE 5 within 24 hours. Bringing the unit to MODE 5 is a conservative action with regard to decay heat removal. With only one RHR loop OPERABLE, redundancy for decay heat removal is lost and, in the event of a loss of the remaining RHR loop, it would be safer to initiate that loss from MODE 5 (≤ 200°F) rather than MODE 4 (200 to 300°F). The Completion Time of 24 hours is a reasonable time, based on operating experience, to reach MODE 5 from MODE 4 in an orderly manner and without challenging plant systems.

Only OPERABLE

C.1 and C.2

If no loop is OPERABLE or in operation, except during conditions permitted by Note 1 in the LCO section, all operations involving a reduction of RCS boron concentration must be suspended and action to restore one RCS or RHR loop to OPERABLE status and operation must be initiated. Boron dilution requires forced circulation for proper mixing, and the margin to criticality must not be reduced in this type of operation. The immediate Completion Times reflect the importance of maintaining operation for decay heat removal. The action to restore must be continued until one loop is restored to OPERABLE status and operation.

in

SURVEILLANCE REQUIREMENTS

SR 3.4.6.1

This SR requires verification every 12 hours that one RCS or RHR loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RCS and RHR loop performance.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.6.2

actual

SR 3.4.6.2 requires verification of SG OPERABILITY. SG OPERABILITY is verified by ensuring that the secondary side narrow range water level is ≥ 17%. If the SG secondary side narrow range water level is < 17%, the tubes may become uncovered and the associated loop may not be capable of providing the heat sink necessary for removal of decay heat. The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to the loss of SG level.

DB.2

71

Insert: B 3.1-31-01

actual

SR 3.4.6.3

Verification that the required pump is OPERABLE ensures that an additional RCS or RHR pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the required pump and associated support systems. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES

~~None~~. 1. FSAR Chapter 14.

INSERT: B 3.4-31-01

DB2

is ≥ 71% (wide range equivalent) for each required loop. Depending on plant conditions, either wide range or narrow range SG level instruments may be used to verify this SR is met. Operators may be required to adjust the indicated level to compensate for the effects of SG temperature.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.6:
"RCS Loops - MODE 4"

PART 6:

Justification of Differences between

NUREG-1431 and IP3 ITS

JUSTIFICATION OF DIFFERENCES FROM NUREG-1431
ITS SECTION 3.4.6 - RCS Loops - MODE 4

RETENTION OF EXISTING REQUIREMENT (CURRENT LICENSING BASIS)

None

PLANT-SPECIFIC WORDING PREFERENCE OR MINOR EDITORIAL IMPROVEMENT

PA.1 Corrected typographical error or made a minor editorial improvement to improve clarity and ensure requirements are fully understood and consistently applied. There are no technical changes to requirements as specified in NUREG 1431, Rev. 1; therefore, this change is not a significant or generic deviation from NUREG 1431, Rev 1.

PLANT-SPECIFIC DIFFERENCE IN THE DESIGN OR DESIGN BASIS

DB.1 Design or implementation details are incorporated or revised as necessary to more precisely describe IP3 current design or practice. These changes are intended to describe the design, improve clarity, or ensure requirements are fully understood and consistently applied. Unless identified and described blow, these changes are self-explanatory. A detailed description of the design, accident analysis assumptions, and Operability requirements are incorporated into the IP3 ITS Bases. These changes maintain the IP3 current licensing basis except as identified and justified in the CTS/ITS discussion of changes.

DB.2 IP3 clarifies the wording the SR that requires periodic verification of SG water level to ensure that the acceptance criteria clearly require that SG tubes are covered. This change is needed because IP3 SG wide range and narrow range level instruments use a different starting reference. Additionally, depending on plant conditions, either wide range or narrow range SG level instruments may be the only instruments available to verify this SR is met. Finally, operators may be required to adjust the indicated level to compensate for the effects of SG temperature because the indicated level may be affected by the SG temperature relative to the temperature at which level the level calibration was performed. This change has no significant adverse impact on safety.

DB.3 NUREG 1431, Rev 1, LCO 3.4.6, Note 2, specifies that no RCP shall be started with any RCS cold leg temperature ≤ 319°F unless the secondary side water temperature of each steam generator (SG) is ≤ 64°F above each of the RCS cold leg temperatures.

IP3 ITS LCO 3.4.6, Note 2, specifies that no RCP shall be started below the LTOP arming temperature unless the requirements of LCO 3.4.12, Low Temperature Overpressure Protection (LTOP), are met.

This change is needed and is acceptable because pump starting limitations imposed by LCO 3.4.12, LTOP, are significantly more complicated and restrictive than the limitations described in NUREG 1431, Rev 1, LCO 3.4.6, Note 2.

DB.4 NUREG 1431, Rev 1, LCO 3.4.6, Note 2, specifies that no RCP shall be started "with any RCS cold leg temperature" ≤ 319°F unless specified requirements are met.

IP3 ITS LCO 3.4.6, Note 2, specifies that no RCP shall be started with the "average of the RCS cold leg temperatures" less than the LTOP arming temperature unless the requirements of LCO 3.4.12, Low Temperature Overpressure Protection (LTOP), are met.

This change is needed and is acceptable because the IP3 LTOP analysis is based on the "average of the RCS cold leg temperatures" and not the loop with the lowest temperature.

DIFFERENCE BASED ON A GENERIC CHANGE TRAVELER FOR NUREG-1431

T.1 This change incorporates Generic Change TSTF-153, Rev.0 (WOG-63) which rewords notes taking exception to LCO requirements to be consistent with the wording of the requirement. Specifically, the LCO contains a Note taking exception to the LCO requirement for pumps to "be in operation" but states the exception as "may be de-energized." Therefore, each Note is revised to provide wording consistent with the requirement being excepted.

DIFFERENCE FOR ANY REASON OTHER THAN ABOVE

None

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.7:
"RCS Loops - MODE 5, Loops Filled"

PART 1:

Indian Point 3
Improved Technical Specifications and Bases

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.7 RCS Loops – MODE 5, Loops Filled

LCO 3.4.7 One residual heat removal (RHR) loop shall be OPERABLE and in operation, and either:

a. One additional RHR loop shall be OPERABLE; or

b. The secondary side actual water level of at least one steam generator (SG) shall be ≥ 71% (wide range equivalent).

---------- NOTES ----------

1. The RHR pump of the loop in operation may not be in operation for ≤ 1 hour per 8 hour period provided:

   a. No operations are permitted that would cause reduction of the RCS boron concentration; and

   b. Core outlet temperature is maintained ≥ 10°F below saturation temperature.

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.

3. No reactor coolant pump shall be started with the average of the RCS cold leg temperatures less than the LTOP enable temperature unless the requirements of LCO 3.4.12, Low Temperature Overpressure Protection (LTOP), are met.

4. All RHR loops may be removed from operation during planned heatup to MODE 4 when at least one RCS loop is in operation.

APPLICABILITY: MODE 5 with RCS loops filled.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One RHR loop inoperable. AND Required SGs secondary side actual water level not within the limit.	A.1	Initiate action to restore a second RHR loop to OPERABLE status.	Immediately
	OR		
	A.2	Initiate action to restore required SG secondary side water level to within the limit.	Immediately
B. Required RHR loops inoperable. OR No RHR loop in operation.	B.1	Suspend all operations involving a reduction of RCS boron concentration.	Immediately
	AND		
	B.2	Initiate action to restore one RHR loop to OPERABLE status and in operation.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.7.1	Verify one RHR loop is in operation.	12 hours
SR 3.4.7.2	Verify SG secondary side actual water level is ≥ 71% (wide range equivalent) in required SG.	12 hours
SR 3.4.7.3	Verify correct breaker alignment and indicated power are available to the required RHR pump that is not in operation.	7 days

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.7 RCS Loops – MODE 5, Loops Filled

BASES

BACKGROUND

In MODE 5 with the RCS loops filled, the primary function of the reactor coolant is the removal of decay heat and transfer this heat either to the steam generator (SG) secondary side coolant, via natural circulation (Ref. 1), or the component cooling water via the residual heat removal (RHR) heat exchangers. While the principal means for decay heat removal is via the RHR System, the SGs, via natural circulation (Ref. 1), are specified as a backup means for redundancy. Even though the SGs cannot produce steam in this MODE, they are capable of being a heat sink due to their large contained volume of secondary water. As long as the SG secondary side water is at a lower temperature than the reactor coolant, heat transfer will occur. The rate of heat transfer is directly proportional to the temperature difference. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

In MODE 5 with RCS loops filled, the reactor coolant is circulated by means of two RHR loops connected to the RCS, each loop containing an RHR heat exchanger, an RHR pump, and appropriate flow and temperature instrumentation for control, protection, and indication. One RHR pump circulates the water through the RCS at a sufficient rate to prevent boric acid stratification. The boron concentration in the pressurizer is of no concern because of the low pressurizer volume and because the pressurizer boron concentration will be higher than the rest of the reactor coolant.

Each RHR loop consists of one RHR pump and one RHR heat exchanger as well as associated piping and valves to transfer heat between the RHR heat exchanger and the core. Although either RHR heat exchanger may be credited for either RHR loop, one RHR heat exchanger must be OPERABLE for each OPERABLE RHR loop.

The number of loops in operation can vary to suit the operational needs. The intent of this LCO is to provide forced flow from at least one RHR loop for decay heat removal and transport. The flow provided by one RHR loop is adequate for decay heat removal.

BASES

BACKGROUND (Continued)

The other intent of this LCO is to require that a second path be available to provide redundancy for heat removal.

The LCO provides for redundant paths of decay heat removal capability. The first path can be an RHR loop that must be OPERABLE and in operation. The second path can be another OPERABLE RHR loop or maintaining one SG with secondary side water level ≥ 71% (wide range equivalent) to provide an alternate method for decay heat removal via natuaral circulation (Ref. 1).

When using a SG 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 SG (Ref.1).

During natural circulation, the SG 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 SG 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) satisfy Criterion 4 of 10 CFR 50.36.

BASES

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 one SG with secondary side water level ≥ 71% (wide range equivalent). 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 one SG with secondary side water level ≥ 71% (wide range equivalent). Should the operating RHR loop fail, the SG could be used to remove the decay heat via natural circulation.

Note 1 permits all RHR pumps to not be in operation ≤ 1 hour per 8 hour period. The purpose of the Note is to permit testing and maintenance that can be performed only when in MODE 5 with no forced circulation. This allowance 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 maintenance or test procedures:

a. No operations are permitted that would dilute the RCS boron concentration, therefore maintaining the margin to criticality. Boron reduction is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation; and

b. Core outlet temperature is maintained ≥ 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 MODE 5 with no forced circulation.

BASES

LCO (continued)

Note 3 requires that the reactor coolant pump starting requirements of LCO 3.4.12, Low Temperature Overpressure Protection (LTOP), must be met before the start of a reactor coolant pump (RCP) with an RCS cold leg temperature less than the LTOP arming temperature specified in LCO 3.4.12, Low Temperature Overpressure Protection (LTOP), are met. This restriction is to prevent a low temperature overpressure event due to a thermal transient when an RCP is started.

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 with forced flow or natural circulation when it has an adequate water level and is OPERABLE in accordance with the Steam Generator Tube Surveillance Program.

If the SG being credited as the redundant method of decay heat removal depends on natural circulation (Ref.1), the SG is considered OPERABLE only if:

a. RCS loop and reactor pressure vessel filling and venting are complete; and,

b. RCS pressure has been maintained ≥ 100 psig since the most recent filling and venting.

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 actual

BASES

APPLICABILITY (continued)

secondary side water level of at least one SG is required to be ≥ 71% (wide range equivalent).

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

A.1 and A.2

If one RHR loop is inoperable and the required SG has secondary side water level < 71% (wide range equivalent) redundancy for heat removal is lost. Action must be initiated immediately to restore a second RHR loop to OPERABLE status or to restore the required SG secondary side water level. Either Required Action A.1 or Required Action A.2 will restore redundant heat removal paths. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

B.1 and B.2

If no RHR loop is in operation, except during conditions permitted by Note 1, or if no loop is OPERABLE, all operations involving a reduction of RCS boron concentration must be suspended and action to restore one RHR loop to OPERABLE status and in operation must be initiated. To prevent boron dilution, forced circulation is required to provide proper mixing and preserve the margin to criticality in this type of operation. The immediate Completion Times reflect the importance of maintaining operation for heat removal.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1

This SR requires verification every 12 hours that the required loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RHR loop performance.

SR 3.4.7.2

Verifying that at least one SG is OPERABLE by ensuring the secondary side water level ≥ 71% (wide range equivalent) ensures an alternate decay heat removal method, via natural circulation, in the event that the second RHR loop is not OPERABLE. If both RHR loops are OPERABLE, this Surveillance is not needed. The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to the loss of SG level.

SR 3.4.7.3

Verification that a second RHR pump is OPERABLE ensures that an additional pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the RHR pump. If secondary side water level is ≥ 71% (wide range equivalent) in at least one SG, this Surveillance is not needed. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

BASES

REFERENCES

1. NRC Information Notice 95-35, "Degraded Ability of Steam Generators to Remove Decay Heat by Natural Circulation."

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Technical Specification 3.4.7:
"RCS Loops - MODE 5, Loops Filled"

PART 2:

CURRENT TECHNICAL SPECIFICATION PAGES

Annotated to show differences between CTS and ITS

CTS pages and associated TSCRs annotated for this ITS Specification :

CTS Page No.	Effective Amendment	Annotated Amendment	TSCR No.	TSCR Description	ITS Status of TSCR
3.1-1	121	121	No TSCRs	No TSCRs for this Page	N/A
3.1-2	179	179	No TSCRs	No TSCRs for this Page	N/A
3.1-3	179	179	No TSCRs	No TSCRs for this Page	N/A
3.1-7	121	121	No TSCRs	No TSCRs for this Page	N/A
3.3-5	53	53	No TSCRs	No TSCRs for this Page	N/A
3.3-5a	179	179	No TSCRs	No TSCRs for this Page	N/A

A.1

3. LIMITING CONDITIONS FOR OPERATION

SEE ITS 3.0

For the cases where no exception time is specified for inoperable components, this time is assumed to be zero.

3.1 REACTOR COOLANT SYSTEM

A.2

~~Applicability~~

~~Applies to the operating status of the Reactor Coolant System: operational components; heatup; cooldown; criticality; activity; chemistry and leakage.~~

~~Objective~~

~~To specify those limiting conditions for operation of the Reactor Coolant System which must be met to ensure safe reactor operation.~~

Specification

A. OPERATIONAL COMPONENTS

1. Coolant Pumps

SEE ITS 3.4.5 and 3.4.6

LCO 3.4.7, Note 1.c Req. Act. B.1

a. When a reduction is made in the boron concentration of the reactor coolant, at least one reactor coolant pump or one residual heat removal pump (connected to the Reactor Coolant System) shall be in operation.

SEE ITS 3.4.5

b. (1) When the reactor coolant system T_{avg} is greater than 350°F and electrical power is available to the reactor coolant pumps, and as permitted during special plant evolutions, at least one reactor coolant pump shall be in operation. All reactor coolant pumps may be de-energized for up to 1 hour provided no operations are permitted that would cause dilution of the reactor coolant system boron concentration, and core outlet temperature is maintained at least 10°F below saturation temperature.

(2) When the reactor is subcritical and reactor coolant system T_{avg} is greater than 350°F, control bank withdrawal shall be prohibited unless four reactor coolant pumps are operating.

SEE ITS 3.4.6

c. When the reactor coolant system T_{avg} is greater than 200°F and less than 350°F, and as permitted during special plant evolutions, at least one reactor coolant pump or one residual heat removal pump (connected to the Reactor Coolant System) shall be in operation. All reactor coolant pumps may be de-energized with RHR not in service for up to 1 hour provided no operations are permitted that would cause dilution of the reactor coolant system boron concentration, and core outlet temperature is maintained at least 10°F below saturation temperature.

Mode 5, Loops Filled

LCO 3.4.7 Applicability

LCO 3.4.7

LCO 3.4.7, Note 1

~~d.~~ When the reactor coolant system T_{avg} is less than 200°F, but not in the refueling operation condition and as permitted during special plant evolutions, at least one residual heat removal pump (connected to the Reactor Coolant System) shall be in operation. This RHR pump may be out of service for up to 1 hour provided no operations are permitted that would cause dilution of the reactor coolant system boron concentration, and core outlet temperature is maintained at least 10°F below saturation temperature. (per 8 hour period)

A.6 A.4 A.3 M.1

e. When the reactor is critical and above 2% rated power, except for natural circulation tests, at least two reactor coolant pumps shall be in operation.

SEE ITS 3.4.4 ITS 3.4.17

f. The reactor shall not be operated at power levels above 10% rated power with less than four (4) reactor coolant loops in operation.

g. If the requirements of 3.1.A.1.e and 3.1.A.1.f above cannot be satisfied, the reactor shall be brought to the hot shutdown condition within 1 hour.

h. A reactor coolant pump (RCP) may not be started (or jogged) when the RCS cold leg temperature (T_{cold}) is at or below 319°F, unless RCS make up is not in excess of RCS losses, and one of the following requirements is met:

(1) The OPS is operable, steam generator pressure is not decreasing, and the temperature of each steam generator is less than or equal to the coldest T_{cold};

Or

SEE ITS 3.4.12

(2) The OPS is operable, the temperature of the hottest steam generator exceeds the coldest T_{cold} by no more than 64°F, pressurizer level is at or below 73 percent, and T_{cold} is as per Figure 3.1.A-1;

Or

(3) With OPS inoperable, steam generator pressure is not decreasing, the temperature of each steam generator is less than or equal to the coldest T_{cold}, pressurizer level is at or below 73 percent, and the RCS pressure does not exceed that given by Fig. 3.1.A-2. The pressurizer level must be further restricted per Figures 3.1.A-5 and 3.1.A-6 if operation below 319°F exceeds 8 hours.

LCO 3.4.7, Note 3

A.5

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A.1

A.1

Basis

When the boron concentration of the Reactor Coolant System is to be reduced the process must be uniform to prevent sudden reactivity changes in the reactor. Mixing of the reactor coolant will be sufficient to maintain a uniform boron concentration if at least one reactor coolant pump or one residual heat removal pump is running while the change is taking place. The residual heat removal pump will circulate the primary system volume in approximately one half hour. The pressurizer is of no concern because of the low pressurizer volume and because the pressurizer boron concentration will be higher than that of the rest of the reactor coolant.

Heat transfer analyses show that reactor heat equivalent to 10% of rated power (P-7) can be removed with natural circulation only (1); hence, the requirement for one operating RCP above 350°F and two operating RCP's above 2% rated power provides a substantial safety factor. In addition, a single RCP or RHR pump (connected to the RCS) provides sufficient heat removal capability for removing decay heat.

The restriction on control bank withdrawal with less than four reactor coolant pumps operating when the reactor is subcritical and RCS T_{avg} is greater than 350°F is necessary to conform with the assumptions used in the transient analyses for the uncontrolled control rod withdrawal event from subcritical condition. The FSAR safety analysis for uncontrolled control rod assembly withdrawal from a subcritical condition assumes all four reactor coolant pumps to be operating within the temperature range of concern. Using this assumption the DNB design basis is satisfied for the combination of the two banks of the maximum combined worth withdrawn at maximum speed. Since there is no mechanism by which the control rods can be automatically withdrawn due to a control system error when T_{avg} is between 350°F and the no-load temperature, such an event can only be initiated as a result of human error during rod manipulation. Prohibiting control bank withdrawal with less than four RCPs operating provides assurance that the plant is operated within the accident analysis assumptions.

The reactor shall not be operated at power levels above 10% rated power with less than four (4) reactor coolant loops in operation until safety analyses for less than four loop operation have been submitted by the licensee and approval for less than four loop operation at power levels above 10% rated power has been granted by the Commission. (See license condition 2.C. (3))

Each of the pressurizer code safety valves is designed to relieve 420,000 lbs. per hr. of saturated steam at the valve set point.

If no residual heat were removed by the Residual Heat Removal System the amount of steam which could be generated at safety valve relief pressure would be less than half the capacity of a single valve. One valve therefore provides adequate protection for overpressurization.

The combined capacity of the three pressurizer safety valves is greater than the maximum surge rate resulting from complete loss of load (2) without a direct reactor trip or any other control.

Amendment No. 48, 53, 84, 121

Add SR 3.4.7.1, SR 3.4.7.2 & SR 3.4.7.3 — M.2

5. If the Safety Injection and Residual Heat Removal Systems are not restored to meet the requirements of 3.3.A.3 within the time periods specified in 3.3.A.4; then:

a. If the reactor is critical, it shall be in the hot shutdown condition within four hours and the cold shutdown condition within the following 24 hours.

SEE ITS 3.5.1, ITS 3.5.2, ITS 3.5.3, ITS 3.5.4

b. If the reactor is subcritical, the reactor coolant system temperature and pressure shall not be increased more than 25°F and 100 psi, respectively, over existing values. If the requirements of 3.3.A.3 are not satisfied within an additional 48 hours, the reactor shall be brought to the cold shutdown condition using normal operating procedures. The shutdown shall start no later than the end of the 48 hour period.

6. When the reactor coolant system T_{avg} is greater than 200°F and less than 350°F, the following decay heat removal requirements shall be met:

a. Two residual heat removal pumps together with their associated heat exchangers, piping, and valves shall be operable,

OR

b. A minimum of one residual heat removal pump and heat exchanger and a minimum of one reactor coolant pump and steam generator together with their associated piping and valves, shall be operable,

SEE ITS 3.4.6

OR

c. A minimum of two reactor coolant pumps and two steam generators, together with their associated piping and valves, shall be operable,

OR

d. With less than the above operable, initiate corrective action to return the required equipment to an operable status as soon as possible and suspend any operations which would reduce the boron concentration of the reactor coolant system. Otherwise, if sufficient equipment is available, be in cold shutdown within 20 hours. — A.6

LCO 3.4.7 Applicability

7. When the reactor coolant T_{avg} is less than 200°F, but not in the refueling operation condition, two residual heat removal pumps, together with their associated heat exchangers, piping and valves, shall be operable. — Mode 5, Loops Filled; loops — LA.1 — A.3

LCO 3.4.7

a. With less than the above operable, initiate corrective action to return the required equipment to an operable status as soon as possible and suspend any operations which would reduce the boron concentration of the reactor coolant system.

b. The above requirements may be suspended during maintenance, modifications, testing, inspection or repair provided that:

1) an alternate means of decay heat removal is available and return of the system within sufficient time to prevent exceeding cold shutdown requirements is assured; — M.3

Add LCO 3.4.7, Notes 2 and 4 — L.2

Add LCO 3.4.7.b — L.1

M.3

~~2) RCS temperature and the source range detectors are monitored hourly;~~

~~and~~

~~3) no operations are permitted which would reduce the boron concentration of the reactor coolant system.~~

8. When the RCS average cold leg temperature (T_{cold}) is below 319°F, or when RHR is in service (i.e., not isolated from the RCS), no safety injection pumps shall be energized and aligned to feed the RCS.

9. The requirements of 3.3.A.8 may be relaxed to allow one safety injection pump energized and aligned to feed the RCS under the following circumstances:

   a. emergency boration; OR

   b. for pump testing, for a period not to exceed 8 hours; OR

   c. loss of RHR cooling.

SEE ITS 3.4.12

10. The requirements of 3.3.A.8 may be further relaxed when the RCS is < 200°F, such that two safety injection pumps may be energized and aligned to feed the RCS under the following circumstances:

   a. the RCS is vented with an opening greater than or equal to the size of one code pressurizer safety valve flange, OR

   b. indicated pressurizer level is at 0% and the plant is vented in accordance with Technical Specification 3.1.A.8.c.1. (Alternate methods and instrumentation may be used to confirm actual RCS elevation.)

B. Containment Cooling and Iodine Removal Systems

1. The reactor shall not be brought above the cold shutdown condition unless the following requirements are met:

   a. The spray additive tank contains a minimum of 4000 gallons of solution with a sodium hydroxide concentration ≥35% and ≤38% by weight.

   b. The five fan cooler-charcoal filter units and the two spray pumps, with their associated valves and piping, are operable.

SEE ITS 3.6.6

2. The requirements of 3.3.B.1 may be modified to allow any one of the following components to be inoperable at one time:

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PART 3:

DISCUSSION OF CHANGES

Differences between CTS and ITS

DISCUSSION OF CHANGES
ITS SECTION 3.4.7 - RCS Loops - MODE 5, Loops Filled

ADMINISTRATIVE

A.1 In the conversion of the Indian Point Unit 3 Current Technical Specifications (CTS) to the plant specific Improved Technical Specifications (ITS) certain wording preferences or conventions are adopted which do not result in technical changes (either actual or interpretational). Additionally, editorial changes, reformatting, and revised numbering are adopted to make ITS consistent with the conventions in NUREG-1431, Standard Technical Specifications, Westinghouse Plants, Rev. 1, i.e., the improved Standard Technical Specifications.

The CTS Bases are deleted and replaced with comprehensive ITS Bases that are designed to support interpretation and implementation of the associated Technical Specifications. The Bases explain, clarify, and document the reasons (i.e., bases) for the associated Technical Specifications, and reflect the IP3 plant specific design, analyses, and licensing basis. In accordance with 10 CFR 50.36(a), the ITS Bases are included with the proposed ITS conversion application; however, deletion of the CTS Bases and the adoption of the ITS Bases is an administrative change with no impact on safety.

A.2 CTS Limiting Conditions for Operation (LCOs) and Surveillance Requirements (SRs) include statements of the objective and the applicability. The CTS statements of objective and applicability are deleted because these statements do not establish any requirements and do not provide any guidance for the application of CTS requirements. Therefore, deletion of these statements has no significant adverse impact on safety.

A.3 The combination of CTS 3.1.A.1.d and CTS 3.3.A.7 establish requirements for decay heat removal when the reactor coolant system Tavg is less than 200°F but not in the refueling condition (Mode 6) (See ITS 3.4.7, DOC A.6). CTS 3.1.A.1.d requires at least one residual heat removal pump in operation. CTS 3.3.A.7 requires two residual heat removal pumps be operable. ITS LCO 3.4.7 establishes requirements consistent with the combination of the two existing CTS requirements. The reorganization of

requirements is an administrative change with no adverse impact on safety.

A.4 CTS 3.1.A.1.d specifies that CTS requirements for decay heat removal may be modified "as permitted during special plant evolutions." ITS 3.4.7 deletes this exception to the LCO applicability because it is ambiguous and does not provide any clearly identifiable requirements or allowances. Therefore, deletion of this statement results in no change to the existing requirements. Therefore, this is an administrative change with no impact on safety.

A.5 CTS 3.1.A.1.h establishes requirements for starting reactor coolant pumps (RCPs) when reactor coolant system temperature is below the low temperature overpressure protection (LTOP) enable temperature. ITS LCO 3.4.12, Low Temperature Overpressure Protection (LTOP), includes surveillance requirements that maintain these allowances and requirements (See ITS 3.4.12). ITS LCO 3.4.7, Note 3, is added to ensure that ITS LCO 3.4.12 requirements are met prior to starting RCPs when in Mode 5. The addition of ITS LCO 3.4.7, Note 3, is an administrative change with no adverse impact on safety because it is a cross reference between ITS LCO 3.4.7 and ITS LCO 3.4.12 requirements.

A.6 The combination of CTS 3.1.A.1.d and CTS 3.3.A.7 establish requirements for decay heat removal when the reactor coolant system Tavg is less than 200°F but not in the refueling condition (Mode 5). CTS 3.1.A.1.d and CTS 3.3.A.7 do not make an explicit distinction between Mode 5 with loops filled and Mode 5 with loops not filled; however, with loops not filled a SG is not capable of removing decay heat.

ITS LCO 3.4.7, RCS Loops - Mode 5, Loops Filled, and ITS LCO 3.4.8, RCS Loops - Mode 5, Loops Not Filled, establish requirements consistent with the combination of the two CTS requirements. The primary difference between ITS LCO 3.4.7 and ITS LCO 3.4.8 is that if the RCS loops are filled then a filled SG can be credited as an alternate method of decay heat removal in place of an RHR loop that is not operating. This is consistent with a reasonable interpretation of the CTS. Therefore, this

reorganization of requirements is an administrative change with no adverse impact on safety.

MORE RESTRICTIVE

M.1 CTS 3.1.A.1.d allows all RHR pumps to be de-energized for up to 1 hour in Mode 5 provided that: a) no operations are permitted that would cause dilution of the reactor coolant system boron concentration; and, b) core outlet temperature is maintained at least 10°F below saturation temperature.

ITS LCO 3.4.7, Note 1, maintains the same allowance; however, ITS LCO 3.4.7 limits the use of this allowance to once in any 8 hour period. This change is needed to ensure that the intent of CTS 3.1.A.1.d (forced circulation in Mode 5) is met and to eliminate any ambiguity regarding the application of the allowance that may be needed to perform required maintenance or testing in Mode 5. This more restrictive change is acceptable because it does not introduce any operation which is un-analyzed while ensuring the intent of LCO 3.4.7, to maintain forced flow in the reactor when in Mode 5, is met. Therefore, this change has no adverse impact on safety.

M.2 CTS 3.1.A.1.d and CTS 3.3.A.7 establish requirements for a minimum number RHR pumps that must be in operation and/or Operable in Mode 5 with loops filled; however, no surveillance tests are established to verify that these requirements are met. ITS LCO 3.4.7 requires periodic verification that requirements are met as follows:

ITS SR 3.4.7.1 is added to verify every 12 hours that the required RHR loop is in operation;

ITS SR 3.4.7.2 is added to verify every 12 hours that the minimum steam generator secondary side water level is acceptable if the SG is being used to satisfy requirements of ITS LCO 3.4.7; and,

ITS SR 3.4.7.3 is added to verify every 7 days that the breaker alignment and indicated power are available to the required RHR pump that is not in operation if a second RHR loop is being used

to satisfy requirements of ITS LCO 3.4.7.

This more restrictive change is acceptable because it does not introduce any operation which is un-analyzed while requiring periodic verification that each RCS loop is operating and/or Operable as required by the LCO. Therefore, this change has no adverse impact on safety.

M.3 CTS 3.3.A.7.b allows an alternate means of decay heat removal to be used in place of one or both RHR loops without any time restrictions as long as the alternate method is capable of maintaining RCS temperature. This is a special allowance that may be used during maintenance, modifications, testing, inspection or repair.

ITS LCO 3.4.7 does not include an allowance for unlimited use of a temporary decay heat removal system as one of the two required decay heat removal systems (although ITS 3.4.7 does permit the use of a SG as the backup decay heat removal system (See ITS 3.4.7, DOC L.1)).

Deletion of CTS 3.3.A.7.b is needed and is acceptable because ITS LCO 3.4.7 provides appropriate allowances for performing required testing and maintenance which could temporarily render one of the two required decay heat removal systems inoperable.

This more restrictive change is acceptable because it does not introduce any operation which is un-analyzed while eliminating the option for unlimited use of a temporary decay heat removal system as one of the two required decay heat removal systems Therefore, this change has no adverse impact on safety.

LESS RESTRICTIVE

L.1 CTS 3.1.A.1.d requires one RHR pump be operating when in Mode 5. CTS 3.3.A.7 requires that two RHR pumps be Operable in Mode 5 but allows the requirements for two Operable RHR pumps in Mode 5 to be suspended during maintenance, modifications, testing, inspection or repair provided that an alternate means of decay heat removal is available and return of the system within sufficient time to prevent exceeding cold shutdown requirements is assured (See ITS 3.4.7, DOC M.3).

ITS LCO 3.4.7 requires one RHR loop be Operable and in operation and either one additional RHR loop or the secondary side water level of at least one steam generator (SG) with the secondary side filled to a level that ensures the tubes are covered. Therefore, ITS 3.4.7 allows a SG to be used as the redundant decay heat removal capability at any time in Mode 5 when loops are filled. This change is acceptable because of the following: a) the filled SG may be used as a backup only and ITS 3.4.7 still requires at least one RHR loop operable and one RHR pump in operation; and, b) a filled SG with a filled RCS loop is capable of providing adequate decay heat removal capability in Mode 5 with either forced or natural circulation. Therefore, this change has no adverse impact on safety.

L.2 ITS LCO 3.4.7, Notes 2 and 4, add two new allowances to the requirements for decay heat removal capability in Mode 5.

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. This change is acceptable because the decay heat removal capability function is maintained, the duration of the period without redundant decay heat removal capability is limited to 2 hours, and appropriate required actions are provided if both methods of decay heat removal are lost.

Note 4 allows both RHR loops to be removed from operation during planned heatup to Mode 4 when at least one RCS loop is in operation. This change is acceptable because during a planned heatup to Mode 4 at least one RCS loop is in operation which means that plant status is set for RCS temperature to exceed Mode 5 limits.These changes have no significant adverse impact on safety.

REMOVED DETAIL

LA.1 CTS 3.3.A.7 establishes requirements for decay heat removal capability using RHR pumps in Mode 5 that includes a listing of the principal components in the decay heat removal loop such as heat exchangers,

piping and valves. ITS LCO 3.4.7 establishes requirements for residual heat removal system loops except that the details about what constitutes an operable loop are moved to the Bases of ITS 3.4.7.

This change is acceptable because ITS LCO 3.4.7 maintains the Mode 5 requirement to have sufficient decay heat removal capability using RHR loops; therefore, there is no change to the existing requirements and no change to the level of safety of facility operation.

This change, which allows the description of the design of the RHR loops to be maintained in the FSAR and the detailed description of the requirements for Operability of these systems to be maintained in the ITS Bases, is consistent with the approach used in NUREG-1431 for all Limiting Conditions for Operation (LCOs). This approach is acceptable because the requirements of 10 CFR 50.59, Changes, Tests and Experiments, and ITS 5.5.13, Technical Specifications (TS) Bases Control Program, are designed to assure that changes to the FSAR and ITS Bases do not result in changes to the Technical Specification requirements and do not result in significant increases in the probability or consequences of accidents previously evaluated, do not create the possibility of a new or different kind of accident, and do not result in a significant reduction in a margin of safety. Additionally, IP3 programs that implement FSAR changes in accordance with 10 CFR 50.59 and ITS Bases changes in accordance with ITS 5.5.13 require periodic submittal of FSAR and Bases changes to the NRC for review.

This change is a less restrictive administrative change with no impact on safety because no requirements are being deleted from Technical Specifications and an appropriate change control process and an appropriate level of regulatory oversight are maintained for the information being relocated out of the Technical Specifications.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.7:
"RCS Loops - MODE 5, Loops Filled"

PART 4:

No Significant Hazards Considerations
for
Changes between CTS and ITS
that are
Less Restrictive

No Significant Hazard Considerations for Changes that are Administrative, More Restrictive, and Removed Details are the same for all Packages. A Copy is included at the end of the Package.

NO SIGNIFICANT HAZARDS EVALUATION
ITS SECTION 3.4.7 - RCS Loops – MODE 5, Loops Filled

LESS RESTRICTIVE
("L.1" Labeled Comments/Discussions)

New York Power Authority has evaluated the proposed Technical Specification change identified as "Less Restrictive" in accordance with the criteria set forth in 10 CFR 50.92, and has determined that the proposed change does not involve a significant hazards consideration. The bases for the determination that the proposed changes do not involve a significant hazards consideration are discussed below.

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

   This change allows a filled SG and natural circulation in the reactor coolant system to be credited as the backup decay heat removal capability in Mode 5 when the loops are filled. This change will not result in a significant increase in the probability or consequences of an accident previously evaluated because of the following: a) the filled SG may be used as a backup only and ITS 3.4.7 still requires at least one RHR loop operable and one RHR pump in operation; and, b) a filled SG with a filled RCS loop is capable of providing adequate decay heat removal capability in Mode 5 with either forced or natural circulation. Therefore, this change has no adverse impact on safety.

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

   The proposed changes will not involve any physical changes to plant systems, structures, or components (SSC). The changes in normal plant operation are consistent with the current safety analysis assumptions because of the following: a) the filled SG may be used as a backup only and ITS 3.4.7 still requires at least one RHR loop operable and one RHR pump in operation; and, b) a filled SG with a filled RCS loop has been demonstrated to provide adequate decay heat removal capability in Mode 5 with either forced or natural circulation. Therefore, this change has no adverse impact on safety. Therefore, these changes will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

This change does not involve a significant reduction in a margin of safety of the following: a) the filled SG may be used as a backup only and ITS 3.4.7 still requires at least one RHR loop operable and one RHR pump in operation; and, b) a filled SG with a filled RCS loop has been demonstrated to provide adequate decay heat removal capability in Mode 5 with either forced or natural circulation. Therefore, this change has no adverse impact on safety.

LESS RESTRICTIVE
("L.2" Labeled Comments/Discussions)

New York Power Authority has evaluated the proposed Technical Specification change identified as "Less Restrictive" in accordance with the criteria set forth in 10 CFR 50.92, and has determined that the proposed change does not involve a significant hazards consideration. The bases for the determination that the proposed changes do not involve a significant hazards consideration are discussed below.

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

This change add two new allowances to the requirements for decay heat removal capability in Mode 5. 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. Note 4 allows both RHR loops to be removed from operation during planned heatup to Mode 4 when at least one RCS loop is in operation. The Note 2 change will not result in a significant increase in the probability or consequences of an accident previously evaluated because at least one decay heat removal capability is maintained by Note 2, the duration of the period without redundant decay heat removal capability is limited to 2 hours, and appropriate required actions are provided in the LCO if both methods of decay heat removal are lost. The Note 4 change will not result in a significant increase in the probability or consequences of an accident previously evaluated because during a planned heatup to Mode 4 at least one RCS

loop is in operation which means that plant status is set for RCS temperature to exceed Mode 5 limits.

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

   The proposed changes will not involve any physical changes to plant systems, structures, or components (SSC). The changes in normal plant operation are consistent with the current safety analysis assumptions because there is no change to the method of decay heat removal. Therefore, these changes will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   This change does not involve a significant reduction in a margin of safety because of the following:

   Note 2 ensures at least one decay heat removal capability is maintained, the duration of the period without redundant decay heat removal capability is limited to 2 hours, and appropriate required actions are provided in the LCO if both methods of decay heat removal are lost.

   Note 4 recognizes that during a planned heatup to Mode 4 at least one RCS loop is in operation which means that plant status is set for RCS temperature to exceed Mode 5 limits and the RCS loop provides the backup decay heat removal function provided by the RHR loops.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.7:
"RCS Loops - MODE 5, Loops Filled"

PART 5:

NUREG-1431
Annotated to show differences between
NUREG-1431 and ITS

Status of NUREG 1431 Generic Changes for ITS 3.4.7

This ITS Specification is based on NUREG-1431 Specification No. **3.4.7**
as modified by the following Generic Changes:

OG No.	TSTF No.	Generic Change Description	NRC STATUS	IP3 STATUS	JD No.
WOG-055	**114 R0**	REVISE BASES FOR 3.4.7 TO ADDRESS DHR VIA NATURAL CIRCULATION	Approved by NRC	Incorporated.	**T.2**
WOG-063	**153 R0**	CLARIFY EXCEPTION NOTES TO BE CONSISTENT WITH THE REQUIREMENT	Approved by NRC	Incorporated	**T.1**
WOG-067 R1		RELOCATE LTOP ARMING TEMPERATURE TO PTLR	Rejected by TSTF	Not Incorporated	**N/A**

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.7 RCS Loops—MODE 5, Loops Filled

<3.1.A1.d>
<3.3.A.7>
<DOC A3>
<DOC L.1>

LCO 3.4.7 One residual heat removal (RHR) loop shall be OPERABLE and in operation, and either:

a. One additional RHR loop shall be OPERABLE; or

b. The secondary side actual water level of at least ~~[two]~~ one steam generator~~s~~ (SG~~s~~) shall be ~~≥ 17%~~ Insert: 3.4-14-01

PA.1

DB.2

---NOTES---

<3.1.A.1.d>
<DOC M.1>
<3.1.A.1.a>

1. The RHR pump of the loop in operation may be ~~de-energized~~ not be in operation for ≤ 1 hour per 8 hour period provided:

T.1

a. No operations are permitted that would cause reduction of the RCS boron concentration; and

b. Core outlet temperature is maintained ~~at least~~ ≥ 10°F below saturation temperature.

<DOC L.2>

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.

<DOC A5>
<3.1.A.1.h>
<3.1.A.1.i>
<3.1.A.1.j>

3. No reactor coolant pump shall be started with ~~one or more~~ the average of RCS cold leg temperatures ≤ [275]°F unless the secondary side water temperature of each SG is ≤ [50]°F above each of the RCS cold leg temperatures. Insert: 3.4-14-02

DB.3

<DOC L.2>

4. All RHR loops may be removed from operation during planned heatup to MODE 4 when at least one RCS loop is in operation.

<3.1.A.1.d>
<3.3.A.7>
<DOC A.6>

APPLICABILITY: MODE 5 with RCS loops filled.

INSERT: 3.4-14-01

≥ 71% (wide range equivalent) DB.2

INSERT: 3.4-14-02

less than the LTOP arming temperature unless the requirements of LCO 3.4.12, Low Temperature Overpressure Protection (LTOP), are met. DB.3

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
<3.3.A.7.a> A. One RHR loop inoperable. **AND** Required SGs secondary side water level~~s~~ not within limit~~s~~. the <DOC L.1>	A.1 Initiate action to restore a second RHR loop to OPERABLE status.	Immediately
	OR	
	A.2 Initiate action to restore required SG secondary side water level~~s~~ to within limit~~s~~. the	Immediately PA.1
<3.1.A.1.a> <3.3.A.7.a> B. Required RHR loops inoperable. **OR** No RHR loop in operation.	B.1 Suspend all operations involving a reduction of RCS boron concentration.	Immediately
	AND	
	B.2 Initiate action to restore one RHR loop to OPERABLE status and operation. in	Immediately PA.1

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
<DOC M.2> SR 3.4.7.1	Verify one RHR loop is in operation.	12 hours
<DOC M.2> SR 3.4.7.2	Verify SG secondary side actual water level is ≥ [17]% in required SG~~s~~.	12 hours DB.2

Insert: 3.4-15-01

(continued)

INSERT: 3.4-15-01

≥ 71% (wide range equivalent) in DBZ

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.7.3	Verify correct breaker alignment and indicated power are available to the required RHR pump that is not in operation.	7 days

<DOC M.2>

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.7 RCS Loops—MODE 5, Loops Filled

BASES

BACKGROUND

In MODE 5 with the RCS loops filled, the primary function of the reactor coolant is the removal of decay heat and transfer this heat either to the steam generator (SG) secondary side coolant or the component cooling water via the residual heat removal (RHR) heat exchangers. While the principal means for decay heat removal is via the RHR System, the SGs are specified as a backup means for redundancy. Even though the SGs cannot produce steam in this MODE, they are capable of being a heat sink due to their large contained volume of secondary water. As long as the SG secondary side water is at a lower temperature than the reactor coolant, heat transfer will occur. The rate of heat transfer is directly proportional to the temperature difference. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

via natural circulation (Ref. 1)

T.2

In MODE 5 with RCS loops filled, the reactor coolant is circulated by means of two RHR loops connected to the RCS, each loop containing an RHR heat exchanger, an RHR pump, and appropriate flow and temperature instrumentation for control, protection, and indication. One RHR pump circulates the water through the RCS at a sufficient rate to prevent boric acid stratification.

Insert: B3.4-32-01

The number of loops in operation can vary to suit the operational needs. The intent of this LCO is to provide forced flow from at least one RHR loop for decay heat removal and transport. The flow provided by one RHR loop is adequate for decay heat removal. The other intent of this LCO is to require that a second path be available to provide redundancy for heat removal.

Insert: B3.4-32-02

The LCO provides for redundant paths of decay heat removal capability. The first path can be an RHR loop that must be OPERABLE and in operation. The second path can be another OPERABLE RHR loop or maintaining two SG~~s~~ with secondary side water level~~s~~ above ~~117~~ 17% to provide one an alternate method for decay heat removal.

T.2

via natural circulation (Ref. 1)

Insert: B3.4-32-03

(continued)

Typical

INSERT: B 3.4-32-01

DB.1

The pressurizer boron concentration is not a concern because of the low pressurizer volume and because the pressurizer boron concentration will be higher than that of the rest of the reactor coolant.

Each RHR loop consists of one RHR pump and one RHR heat exchanger as well as associated piping and valves to transfer heat between the RHR heat exchanger and the core. Although either RHR heat exchanger may be credited for either RHR loop, one RHR heat exchanger must be OPERABLE for each OPERABLE RHR loop.

INSERT: B 3.4-32-02

DB.2

≥ 71% (wide range equivalent)

INSERT: B 3.4-32-03

X.1

When using a SG 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 SG (Ref.1).

During natural circulation, the SG 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 SG 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).

BASES (continued)

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.

Insert: B 3.4-33-01

RCS Loops—MODE 5 (Loops Filled) have been identified in the NRC Policy Statement as important contributors to risk reduction.

LCO

Insert: B3.4-33-02

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 ≥ [17]%. 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 ≥ [17]%. Should the operating RHR loop fail, the SGs could be used to remove the decay heat.

via natural circulation

Note 1 permits all RHR pumps to be de-energized ≤ 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 de-energizing 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 adequate to perform the test, and operating experience has shown that boron stratification is not likely during this short period with no forced flow.

Insert: B 3.4-33-03

Utilization of Note 1 is permitted provided the following conditions are met, along with any other conditions imposed by initial startup test procedures:

maintenance or

(continued)

INSERT: B 3.4-33-01

satisfy Criterion 4 of 10 CFR 50.36.

INSERT: B 3.4-33-02

71% (wide range equivalent)

DB.2

INSERT: B 3.4-33-03

testing and maintenance that can be performed only when in MODE 5 with no forced circulation. This allowance is acceptable because

BASES

LCO (continued)

a. No operations are permitted that would dilute the RCS boron concentration, therefore maintaining the margin to criticality. Boron reduction is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation; and

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 secondary side water temperature of each SG be ≤ [50]°F above each of the RCS cold leg temperatures before the start of a reactor coolant pump (RCP) with an RCS cold leg temperature ≤ [275]°F. This restriction is to prevent a low temperature overpressure event due to a thermal transient when an RCP is started.

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 when it has an adequate water level and is OPERABLE in accordance with the Steam Generator Tube Surveillance Program.

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,

(continued)

INSERT: B 3.4-34-01

DB3

the reactor coolant pump starting requirements of LCO 3.4.12, Low Temperature Overpressure Protection (LTOP), must be met

INSERT: B 3.4-34-02

DB3

less than the LTOP arming temperature specified in LCO 3.4.12, Low Temperature Overpressure Protection (LTOP), are met.

INSERT: B 3.4-34-03

X.1

If the SG being credited as the redundant method of decay heat removal depends on natural circulation (Ref. 1), the SG is considered OPERABLE only if:

a. RCS loop and reactor pressure vessel filling and venting are complete; and,

b. RCS pressure has been maintained ≥ 100 psig since the most recent filling and venting.

BASES

APPLICABILITY (continued)

or the actual secondary side water level of at least ~~two~~ one SG~~s~~ is required to be ≥ [17]%. DB2

Insert: B 3.4-35-01

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.~~5~~ 4, "Residual Heat Removal (RHR) and Coolant Circulation—High Water Level" (MODE 6); and
LCO 3.9.~~6~~ 5, "Residual Heat Removal (RHR) and Coolant Circulation—Low Water Level" (MODE 6).

ACTIONS

A.1 and A.2

If one RHR loop is inoperable and the required SG~~s~~ ~~have~~ has secondary side water level~~s~~ < [17]% DB2 redundancy for heat removal is lost. Action must be initiated immediately to restore a second RHR loop to OPERABLE status or to restore the required SG secondary side water level~~s~~. Either Required Action A.1 or Required Action A.2 will restore redundant heat removal paths. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

Insert: B 3.4-35-02

B.1 and B.2

If no RHR loop is in operation, except during conditions permitted by Note 1, or if no loop is OPERABLE, all operations involving a reduction of RCS boron concentration must be suspended and action to restore one RHR loop to OPERABLE status and operation must be initiated. To prevent boron dilution, forced circulation is required to provide proper mixing and preserve the margin to criticality in this type of operation. The immediate Completion Times reflect the importance of maintaining operation for heat removal. PA-1

Un

(continued)

INSERT: B 3.4-35-01

≥ 71% (wide range equivalent) DB.2

INSERT: B 3.4-35-02

< 71% (wide range equivalent) DB.2

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1

This SR requires verification every 12 hours that the required loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RHR loop performance.

Insert: B3.4-36-01

SR 3.4.7.2

Verifying that at least two SG~~s~~ ~~are~~ OPERABLE by ensuring the~~ir~~ secondary side ~~narrow range~~ water level~~s~~ ~~are ≥ 17%~~ ensures an alternate decay heat removal method in the event that the second RHR loop is not OPERABLE. If both RHR loops are OPERABLE, this Surveillance is not needed. The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to the loss of SG level.

one is

DB.2

via natural circulation

SR 3.4.7.3

Verification that a second RHR pump is OPERABLE ensures that an additional pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the RHR pump. If secondary side water level is ≥ 17% in at least two SG~~s~~, this Surveillance is not needed. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

Insert: B 3.4-36-02

DB.2

one

REFERENCES

None.

1. NRC Information Notice 95-35, "Degraded ability of Steam Generators to Remove Decay Heat by Natural Circulation."

T.1

X.1

INSERT: B 3.4-36-01

≥ 71% (wide range equivalent) DB.2

INSERT: B 3.4-36-02

≥ 71% (wide range equivalent) DB.2

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.7:
"RCS Loops - MODE 5, Loops Filled"

PART 6:

Justification of Differences between

NUREG-1431 and IP3 ITS

JUSTIFICATION OF DIFFERENCES FROM NUREG-1431
ITS SECTION 3.4.7 - RCS Loops – MODE 5, Loops Filled

RETENTION OF EXISTING REQUIREMENT (CURRENT LICENSING BASIS)

None

PLANT-SPECIFIC WORDING PREFERENCE OR MINOR EDITORIAL IMPROVEMENT

PA.1 Corrected typographical error or made a minor editorial improvement to improve clarity and ensure requirements are fully understood and consistently applied. There are no technical changes to requirements as specified in NUREG 1431, Rev. 1; therefore, this change is not a significant or generic deviation from NUREG 1431, Rev 1.

PLANT-SPECIFIC DIFFERENCE IN THE DESIGN OR DESIGN BASIS

DB.1 Design or implementation details are incorporated or revised as necessary to more precisely describe IP3 current design or practice. These changes are intended to describe the design, improve clarity, or ensure requirements are fully understood and consistently applied. Unless identified and described blow, these changes are self-explanatory. A detailed description of the design, accident analysis assumptions, and Operability requirements are incorporated into the IP3 ITS Bases. These changes maintain the IP3 current licensing basis except as identified and justified in the CTS/ITS discussion of changes.

DB.2 IP3 clarifies the wording the SR that requires periodic verification of SG water level to ensure that the acceptance criteria clearly require that SG tubes are covered. This change is needed because IP3 SG wide range and narrow range level instruments use a different starting reference. Additionally, depending on plant conditions, either wide range or narrow range SG level instruments may be the only instruments available to verify this SR is met. Finally, operators may be required to adjust the indicated level to compensate for the effects of SG temperature because the indicated level may be affected by the SG temperature relative to the temperature at which level the level calibration was performed. This change has no significant adverse impact on safety.

DB.3 NUREG 1431, Rev 1, LCO 3.4.6, Note 2, specifies that no RCP shall be started with any RCS cold leg temperature ≤ [275]°F unless the secondary side water temperature of each steam generator (SG) is ≤ [50]°F above each of the RCS cold leg temperatures.

IP3 ITS LCO 3.4.7, Note 4, specifies that no RCP shall be started with any RCS cold leg temperature less than or equal to the LTOP enable temperature unless the requirements of LCO 3.4.12, Low Temperature Overpressure Protection (LTOP), are met.

This change is needed and is acceptable because pump starting limitations imposed by LCO 3.4.12, LTOP, are significantly more complicated and restrictive than the limitations described in NUREG 1431, Rev 1, LCO 3.4.7, Note 3.

DIFFERENCE BASED ON A GENERIC CHANGE TRAVELER FOR NUREG-1431

T.1 This change incorporates Generic Change TSTF-153, Rev.0 (WOG-63) which rewords notes taking exception to LCO requirements to be consistent with the wording of the requirement. Specifically, the LCO contains a Note taking exception to the LCO requirement for pumps to "be in operation" but states the exception as "may be de-energized." Therefore, each Note is revised to provide wording consistent with the requirement being excepted. This generic change to NUREG-1431, Rev 1, is approved by the NRC.

T.2 This change incorporates Generic Change TSTF-114, Rev.0 (WOG-55) which revises the Bases to clarify that LCO requirements are met natural circulation is relied upon to support the SG being credited as the redundant decay heat removal method. This generic change to NUREG-1431, Rev 1, is approved by the NRC.

DIFFERENCE FOR ANY REASON OTHER THAN ABOVE

X.1 Guidance from NRC Information Notice 95-35, Degraded Ability of Steam Generators to Remove Decay Heat by Natural Circulation, is added

Indian Point 3
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Technical Specification 3.4.8:
"RCS Loops - MODE 5, Loops Not Filled"

PART 1:

Indian Point 3
Improved Technical Specifications and Bases

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.8 RCS Loops – MODE 5, Loops Not Filled

LCO 3.4.8 Two residual heat removal (RHR) loops shall be OPERABLE and one RHR loop shall be in operation.

----------NOTES----------

1. All RHR pumps may not be in operation for ≤ 15 minutes provided:

   a. The core outlet temperature is maintained ≥ 10°F below saturation temperature.

   b. No operations are permitted that would cause a reduction of the RCS boron concentration; and

   c. No draining operations to further reduce the RCS water volume are permitted.

2. One 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 5 with RCS loops not filled.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One RHR loop inoperable.	A.1	Initiate action to restore RHR loop to OPERABLE status.	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required RHR loops inoperable. OR No RHR loop in operation.	B.1 Suspend all operations involving reduction in RCS boron concentration. AND B.2 Initiate action to restore one RHR loop to OPERABLE status and in operation.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.8.1	Verify one RHR loop is in operation.	12 hours
SR 3.4.8.2	Verify correct breaker alignment and indicated power are available to the required RHR pump that is not in operation.	7 days

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.8 RCS Loops – MODE 5, Loops Not Filled

BASES

BACKGROUND

In MODE 5 with the RCS loops not filled, the primary function of the reactor coolant is the removal of decay heat generated in the fuel, and the transfer of this heat to the component cooling water via the residual heat removal (RHR) heat exchangers. The steam generators (SGs) are not available as a heat sink when the loops are not filled. The secondary function of the reactor coolant is to act as a carrier for the soluble neutron poison, boric acid.

In MODE 5 with loops not filled, only RHR pumps can be used for coolant circulation. The number of pumps in operation can vary to suit the operational needs. The intent of this LCO is to provide forced flow from at least one RHR pump for decay heat removal and transport and to require that two loops be available to provide redundancy for heat removal.

Each RHR loop consists of one RHR pump and one RHR heat exchanger as well as associated piping and valves to transfer decay heat between the RHR heat exchanger and the core. Although either RHR heat exchanger may be credited for either RHR loop, one RHR heat exchanger must be OPERABLE for each OPERABLE RHR loop.

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. The flow provided by one RHR loop is adequate for heat removal and for boron mixing.

RCS loops in MODE 5 (loops not filled) satisfy Criterion 4 of 10 CFR 50.36.

BASES

LCO

The purpose of this LCO is to require that at least two RHR loops be OPERABLE and one of these loops be in operation. An OPERABLE loop is one that has the capability of transferring heat from the reactor coolant at a controlled rate. Heat cannot be removed via the RHR System unless forced flow is used. A minimum of one running RHR pump meets the LCO requirement for one loop in operation. An additional RHR loop is required to be OPERABLE to meet redundancy considerations.

Note 1 permits all RHR pumps to not be in operation for ≤ 15 minutes. The circumstances for stopping both RHR pumps are to be limited to situations when the outage time is short and core outlet temperature is maintained ≥ 10°F below saturation temperature. The Note prohibits boron dilution or draining operations when RHR forced flow is stopped.

Note 2 allows one RHR loop to be inoperable for a period of ≤ 2 hours, provided that the other loop is OPERABLE and in operation. This permits periodic surveillance tests to be performed on the inoperable loop when in MODE 5.

An OPERABLE RHR loop is comprised of an OPERABLE RHR pump capable of providing forced flow to an OPERABLE RHR heat exchanger. RHR pumps are OPERABLE if they are capable of being powered and are able to provide flow if required.

APPLICABILITY

In MODE 5 with loops not filled, this LCO requires core heat removal and coolant circulation by the RHR System.

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 3.4.7, "RCS Loops – MODE 5, Loops 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).

BASES

ACTIONS

A.1

If only one RHR loop is OPERABLE and in operation, redundancy for RHR is lost. Action must be initiated to restore a second loop to OPERABLE status. The immediate Completion Time reflects the importance of maintaining the availability of two loops for heat removal.

B.1 and B.2

If no required RHR loops are OPERABLE or in operation, except during conditions permitted by Note 1, all operations involving a reduction of RCS boron concentration must be suspended and action must be initiated immediately to restore an RHR loop to OPERABLE status and operation. Boron dilution requires forced circulation for uniform dilution. When required RHR loops are not OPERABLE or in operation, the margin to criticality must not be reduced. The immediate Completion Time reflects the importance of maintaining operation for heat removal. The action to restore must continue until one loop is restored to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.8.1

This SR requires verification every 12 hours that one loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RHR loop performance.

SR 3.4.8.2

Verification that the required number of pumps are OPERABLE ensures that additional pumps can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the required pumps. The Frequency of 7 days is considered reasonable in view of other

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.8.2 (continued)

administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES None.

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PART 2:

CURRENT TECHNICAL SPECIFICATION PAGES

Annotated to show differences between CTS and ITS

CTS pages and associated TSCRs annotated for this ITS Specification :

CTS Page No.	Effective Amendment	Annotated Amendment	TSCR No.	TSCR Description	ITS Status of TSCR
3.1-1	121	121	No TSCRs	No TSCRs for this Page	N/A
3.1-2	179	179	No TSCRs	No TSCRs for this Page	N/A
3.1-7	121	121	No TSCRs	No TSCRs for this Page	N/A
3.3-5	53	53	No TSCRs	No TSCRs for this Page	N/A
3.3-5a	179	179	No TSCRs	No TSCRs for this Page	N/A

A.1

3. LIMITING CONDITIONS FOR OPERATION

SEE ITS 3.0

For the cases where no exception time is specified for inoperable components, this time is assumed to be zero.

3.1 REACTOR COOLANT SYSTEM

A.2

~~Applicability~~

~~Applies to the operating status of the Reactor Coolant System: operational components; heatup; cooldown; criticality; activity; chemistry and leakage.~~

~~Objective~~

~~To specify those limiting conditions for operation of the Reactor Coolant System which must be met to ensure safe reactor operation.~~

Specification

A. OPERATIONAL COMPONENTS

1. Coolant Pumps

SEE ITS 3.4.5 and 3.4.6

LCO 3.4.8 Note 1.b. Req. Act B.1

a. When a reduction is made in the boron concentration of the reactor coolant, at least one reactor coolant pump or one residual heat removal pump (connected to the Reactor Coolant System) shall be in operation.

SEE ITS 3.4.5

b. (1) When the reactor coolant system T_{avg} is greater than 350°F and electrical power is available to the reactor coolant pumps, and as permitted during special plant evolutions, at least one reactor coolant pump shall be in operation. All reactor coolant pumps may be de-energized for up to 1 hour provided no operations are permitted that would cause dilution of the reactor coolant system boron concentration, and core outlet temperature is maintained at least 10°F below saturation temperature.

(2) When the reactor is subcritical and reactor coolant system T_{avg} is greater than 350°F, control bank withdrawal shall be prohibited unless four reactor coolant pumps are operating.

SEE ITS 3.4.6

c. When the reactor coolant system T_{avg} is greater than 200°F and less than 350°F, and as permitted during special plant evolutions, at least one reactor coolant pump or one residual heat removal pump (connected to the Reactor Coolant System) shall be in operation. All reactor coolant pumps may be de-energized with RHR not in service for up to 1 hour provided no operations are permitted that would cause dilution of the reactor coolant system boron concentration, and core outlet temperature is maintained at least 10°F below saturation temperature.

Mode 5, Loops not filled — A5

d. When the reactor coolant system T_{avg} is less than 200°F, but not in the refueling operation condition, and as permitted during special plant evolutions, at least one residual heat removal pump (connected to the Reactor Coolant System) shall be in operation. This RHR pump may be out of service for up to 1 hour provided no operations are permitted that would cause dilution of the reactor coolant system boron concentration, and core outlet temperature is maintained at least 10°F below saturation temperature. — A.1, A.3, 15 min, M.1

LCO 3.4.8

LCO 3.4.8 Note 1.a Note 1.b

e. When the reactor is critical and above 2% rated power, except for natural circulation tests, at least two reactor coolant pumps shall be in operation.

SEE ITS 3.4.4 ITS 3.4.17

f. The reactor shall not be operated at power levels above 10% rated power with less than four (4) reactor coolant loops in operation.

g. If the requirements of 3.1.A.1.e and 3.1.A.1.f above cannot be satisfied, the reactor shall be brought to the hot shutdown condition within 1 hour.

h. A reactor coolant pump (RCP) may not be started (or jogged) when the RCS cold leg temperature (T_{cold}) is at or below 319°F, unless RCS make up is not in excess of RCS losses, and one of the following requirements is met:

(1) The OPS is operable, steam generator pressure is not decreasing, and the temperature of each steam generator is less than or equal to the coldest T_{cold};

Or

(2) The OPS is operable, the temperature of the hottest steam generator exceeds the coldest T_{cold} by no more than 64°F, pressurizer level is at or below 73 percent, and T_{cold} is as per Figure 3.1.A-1;

Or

(3) With OPS inoperable, steam generator pressure is not decreasing, the temperature of each steam generator is less than or equal to the coldest T_{cold}, pressurizer level is at or below 73 percent, and the RCS pressure does not exceed that given by Fig. 3.1.A-2. The pressurizer level must be further restricted per Figures 3.1.A-5 and 3.1.A-6 if operation below 319°F exceeds 8 hours.

SEE ITS 3.4.12

Add LCO 3.4.8, Note 1.c — M.1

Add SR 3.4.8.1 and 3.4.8.2 — M.2

Basis

When the boron concentration of the Reactor Coolant System is to be reduced the process must be uniform to prevent sudden reactivity changes in the reactor. Mixing of the reactor coolant will be sufficient to maintain a uniform boron concentration if at least one reactor coolant pump or one residual heat removal pump is running while the change is taking place. The residual heat removal pump will circulate the primary system volume in approximately one half hour. The pressurizer is of no concern because of the low pressurizer volume and because the pressurizer boron concentration will be higher than that of the rest of the reactor coolant.

Heat transfer analyses show that reactor heat equivalent to 10% of rated power (P-7) can be removed with natural circulation only (1); hence, the requirement for one operating RCP above 350°F and two operating RCP's above 2% rated power provides a substantial safety factor. In addition, a single RCP or RHR pump (connected to the RCS) provides sufficient heat removal capability for removing decay heat.

The restriction on control bank withdrawal with less than four reactor coolant pumps operating when the reactor is subcritical and RCS T_{avg} is greater than 350°F is necessary to conform with the assumptions used in the transient analyses for the uncontrolled control rod withdrawal event from subcritical condition. The FSAR safety analysis for uncontrolled control rod assembly withdrawal from a subcritical condition assumes all four reactor coolant pumps to be operating within the temperature range of concern. Using this assumption the DNB design basis is satisfied for the combination of the two banks of the maximum combined worth withdrawn at maximum speed. Since there is no mechanism by which the control rods can be automatically withdrawn due to a control system error when T_{avg} is between 350°F and the no-load temperature, such an event can only be initiated as a result of human error during rod manipulation. Prohibiting control bank withdrawal with less than four RCPs operating provides assurance that the plant is operated within the accident analysis assumptions.

The reactor shall not be operated at power levels above 10% rated power with less than four (4) reactor coolant loops in operation until safety analyses for less than four loop operation have been submitted by the licensee and approval for less than four loop operation at power levels above 10% rated power has been granted by the Commission. (See license condition 2.C. (3))

Each of the pressurizer code safety valves is designed to relieve 420,000 lbs. per hr. of saturated steam at the valve set point.

If no residual heat were removed by the Residual Heat Removal System the amount of steam which could be generated at safety valve relief pressure would be less than half the capacity of a single valve. One valve therefore provides adequate protection for overpressurization.

The combined capacity of the three pressurizer safety valves is greater than the maximum surge rate resulting from complete loss of load (2) without a direct reactor trip or any other control.

5. If the Safety Injection and Residual Heat Removal Systems are not restored to meet the requirements of 3.3.A.3 within the time periods specified in 3.3.A.4; then:

SEE ITS 3.5.1 ITS 3.5.2 ITS 3.5.3 ITS 3.5.4

a. If the reactor is critical, it shall be in the hot shutdown condition within four hours and the cold shutdown condition within the following 24 hours.

b. If the reactor is subcritical, the reactor coolant system temperature and pressure shall not be increased more than 25°F and 100 psi, respectively, over existing values. If the requirements of 3.3.A.3 are not satisfied within an additional 48 hours, the reactor shall be brought to the cold shutdown condition using normal operating procedures. The shutdown shall start no later than the end of the 48 hour period.

6. When the reactor coolant system T_{avg} is greater than 200°F and less than 350°F, the following decay heat removal requirements shall be met:

SEE ITS 3.4.6

a. Two residual heat removal pumps together with their associated heat exchangers, piping, and valves shall be operable,

OR

b. A minimum of one residual heat removal pump and heat exchanger and a minimum of one reactor coolant pump and steam generator together with their associated piping and valves, shall be operable,

OR

c. A minimum of two reactor coolant pumps and two steam generators, together with their associated piping and valves, shall be operable,

OR

d. With less than the above operable, initiate corrective action to return the required equipment to an operable status as soon as possible and suspend any operations which would reduce the boron concentration of the reactor coolant system. Otherwise, if sufficient equipment is available, be in cold shutdown within 20 hours.

Mode 5, Loop not filled

LCO 3.4.8 Note 1.b

7. When the reactor coolant T_{avg} is less than 200°F, but not in the refueling operation condition, two residual heat removal pumps, together with their associated heat exchangers, piping and valves, shall be operable. A.5 LA.1 A.3

loops

Req Act. A.1 B.1 B2

a. With less than the above operable, initiate corrective action to return the required equipment to an operable status as soon as possible and suspend any operations which would reduce the boron concentration of the reactor coolant system.

b. The above requirements may be suspended during maintenance, modifications, testing, inspection or repair provided that:

1) an alternate means of decay heat removal is available and return of the system within sufficient time to prevent exceeding cold shutdown requirements is assured; M.3

Add LCO 3.8.4, Note 2 L.1

~~2) RCS temperature and the source range detectors are monitored hourly;~~

~~and~~

~~3) no operations are permitted which would reduce the boron concentration of the reactor coolant system.~~

M.3

8. When the RCS average cold leg temperature (T_{cold}) is below 319°F, or when RHR is in service (i.e., not isolated from the RCS), no safety injection pumps shall be energized and aligned to feed the RCS.

9. The requirements of 3.3.A.8 may be relaxed to allow one safety injection pump energized and aligned to feed the RCS under the following circumstances:

   a. emergency boration; OR

   b. for pump testing, for a period not to exceed 8 hours; OR

   c. loss of RHR cooling.

SEE ITS 3.4.12

10. The requirements of 3.3.A.8 may be further relaxed when the RCS is < 200°F, such that two safety injection pumps may be energized and aligned to feed the RCS under the following circumstances:

   a. the RCS is vented with an opening greater than or equal to the size of one code pressurizer safety valve flange, OR

   b. indicated pressurizer level is at 0% and the plant is vented in accordance with Technical Specification 3.1.A.8.c.1. (Alternate methods and instrumentation may be used to confirm actual RCS elevation.)

B. Containment Cooling and Iodine Removal Systems

1. The reactor shall not be brought above the cold shutdown condition unless the following requirements are met:

   a. The spray additive tank contains a minimum of 4000 gallons of solution with a sodium hydroxide concentration ≥35% and ≤38% by weight.

   b. The five fan cooler-charcoal filter units and the two spray pumps, with their associated valves and piping, are operable.

SEE ITS 3.6.6

2. The requirements of 3.3.B.1 may be modified to allow any one of the following components to be inoperable at one time:

Amendment No. 34, 53, 67, 119, 121, 179

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Improved Technical Specifications (ITS)
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Technical Specification 3.4.8:
"RCS Loops - MODE 5, Loops Not Filled"

PART 3:

DISCUSSION OF CHANGES

Differences between CTS and ITS

DISCUSSION OF CHANGES
ITS SECTION 3.4.8 - RCS Loops – MODE 5, Loops Not Filled

ADMINISTRATIVE

A.1 In the conversion of the Indian Point Unit 3 Current Technical Specifications (CTS) to the plant specific Improved Technical Specifications (ITS) certain wording preferences or conventions are adopted which do not result in technical changes (either actual or interpretational). Additionally, editorial changes, reformatting, and revised numbering are adopted to make ITS consistent with the conventions in NUREG-1431, Standard Technical Specifications, Westinghouse Plants, Rev. 1, i.e., the improved Standard Technical Specifications.

The CTS Bases are deleted and replaced with comprehensive ITS Bases designed to support interpretation and implementation of the associated Technical Specifications. The Bases explain, clarify, and document the reasons (i.e., bases) for the associated Technical Specifications, and reflect the IP3 plant specific design, analyses, and licensing basis. In accordance with 10 CFR 50.36(a), the ITS Bases are included with the proposed ITS conversion application; however, deletion of the CTS Bases and the adoption of the ITS Bases is an administrative change with no impact on safety.

A.2 CTS Limiting Conditions for Operation (LCOs) and Surveillance Requirements (SRs) include statements of the objective and the applicability. The CTS statements of objective and applicability are deleted because these statements do not establish any requirements and do not provide any guidance for the application of CTS requirements. Therefore, deletion of these statements has no significant adverse impact on safety.

A.3 The combination of CTS 3.1.A.1.d and CTS 3.3.A.7 establish requirements for decay heat removal when RCS Tavg is less than 200°F but not in the refueling condition (i.e., Mode 5) (See ITS 3.4.7, DOC A.5). CTS 3.1.A.1.d requires at least one residual heat removal pump in operation. CTS 3.3.A.7 requires two residual heat removal pumps Operable. ITS LCO 3.4.8 establishes requirements consistent with the combination of the

two existing CTS requirements. The reorganization of requirements is an administrative change with no adverse impact on safety.

A.4 CTS 3.1.A.1.d specifies that CTS requirements for decay heat removal may be modified "as permitted during special plant evolutions." ITS LCO 3.4.8 deletes this exception to the LCO applicability because it is ambiguous and does not provide any identifiable requirements or allowances. Therefore, deletion of this statement results in no change to the existing requirements. Therefore, this is an administrative change with no impact on safety.

A.5 The combination of CTS 3.1.A.1.d and CTS 3.3.A.7 establish requirements for decay heat removal when RCS Tavg is less than 200°F but not in the refueling condition (i.e., Mode 5). CTS 3.1.A.1.d and CTS 3.3.A.7 do not make an explicit distinction between Mode 5 with loops filled and Mode 5 with loops not filled; however, if loops are not filled, then a SG is not capable of removing decay heat.

ITS LCO 3.4.7, RCS Loops - Mode 5, Loops Filled, and ITS LCO 3.4.8, RCS Loops - Mode 5, Loops Not Filled, establish requirements consistent with the combination of the two CTS requirements. The primary difference between ITS LCO 3.4.7 and ITS LCO 3.4.8 is that if the RCS loops are filled then a filled SG can be credited as an alternate method of decay heat removal in place of an RHR loop that is not operating. This is consistent with a reasonable interpretation of the CTS. Therefore, this reorganization of requirements is an administrative change with no adverse impact on safety.

MORE RESTRICTIVE

M.1 CTS 3.1.A.1.d allows the RHR pump required to be operating when in Mode 5 to be out of service for up to 1 hour if specified conditions are met regarding boron reduction and saturation temperature. CTS 3.1.A.1.d and CTS 3.3.A.7 do not make a distinction between Mode 5 with loops filled and Mode 5 with loops not filled (See ITS 3.4.8, DOC A.5).

When RCS loops are not filled, ITS 3.4.8, Note 1, reduces the allowance for eliminating forced flow to 15 minutes. Additionally, ITS 3.4.8, Note 1.c, adds an additional requirement that no draining operations are permitted when an RHR loop is not in operation.

These changes are needed because, when in Mode 5 with loops not filled, the SG metal and water mass is not available as a heat sink and the unfilled loop means there is a reduced RCS volume. ITS LCO 3.4.8 recognizes that with unfilled loops the plant is less able to tolerate the absence of decay heat removal or the effects of unplanned draining of the RCS. This more restrictive change is acceptable because it does not introduce any operation that is un-analyzed while requiring more conservative requirements when RCS loops are not filled and forced circulation through the reactor vessel is terminated. Therefore, this change has no adverse impact on safety.

M.2 CTS 3.1.A.1.d and CTS 3.3.A.7 establish requirements for a minimum number RHR pumps that must be in operation and/or Operable in Mode 5 with loops not filled; however, no surveillance tests are established to verify that these requirements are met. ITS LCO 3.4.8 requires periodic verification that requirements are met as follows:

ITS SR 3.4.8.1 is added to verify every 12 hours that the required RHR loop is in operation; and,

ITS SR 3.4.8.2 is added to verify every 7 days that the breaker alignment and indicated power are available to the required RHR pump that is not in operation if a second RHR loop is being used to satisfy requirements of ITS LCO 3.4.8.

This more restrictive change is acceptable because it does not introduce any operation that is un-analyzed while requiring periodic verification that each RCS loop is operating and/or Operable as required by the LCO. Therefore, this change has no adverse impact on safety.

M.3 CTS 3.3.A.7.b allows an alternative means of decay heat removal to be

used in place of one or both RHR loops without any time restrictions as long as the alternate method is capable of maintaining RCS temperature. This is a special allowance that may be used during maintenance, modifications, testing, inspection or repair and was intended to allow use of a temporary decay heat removal system.

ITS LCO 3.4.8 does not include an allowance for unlimited use of a temporary decay heat removal system as one of two required decay heat removal systems (although ITS 3.4.7 does permit use of a SG as a backup decay heat removal system if loops are filled (See ITS 3.4.7, DOC L.1)).

Deletion of CTS 3.3.A.7.b is needed and is acceptable because ITS LCO 3.4.8 provides appropriate allowances for performing required testing and maintenance that could temporarily render one of the two required decay heat removal systems inoperable.

This more restrictive change is acceptable because it does not introduce any operation that is un-analyzed while eliminating the option for unlimited use of a temporary decay heat removal system as one of the two required decay heat removal systems. Therefore, this change has no adverse impact on safety.

LESS RESTRICTIVE

L.1 ITS LCO 3.4.8, Note 2, adds a new allowance to the requirements for decay heat removal capability in Mode 5 when RCS loops are not filled. Note 2 allows one RHR loop to be inoperable for up to 2 hours, provided that the other RHR loop is Operable and in operation. This allowance permits periodic surveillance tests to be performed on the inoperable loop during Mode 5 when decay heat removal requirements justify a temporary loss of redundancy for decay heat removal capacity. This change is acceptable because decay heat removal capability and forced circulation are maintained by the operating RHR loop, the duration of the period without redundant decay heat removal capability is limited to 2 hours, and appropriate required actions are provided in the LCO if both methods of decay heat removal are lost. Therefore, this change has no significant adverse impact on safety.

DISCUSSION OF CHANGES
ITS SECTION 3.4.8 - RCS Loops – MODE 5, Loops Not Filled

REMOVED DETAIL

LA.1 CTS 3.3.A.7 establishes requirements for decay heat removal capability using RHR pumps in Mode 5 that includes a listing of the principle components in the decay heat removal loop such as heat exchangers, piping and valves. ITS LCO 3.4.8 establishes requirements for residual heat removal system loops except that the details about what constitutes an operable loop are moved to the Bases if ITS 3.4.8.

This change is acceptable because ITS LCO 3.4.8 maintains the Mode 5 requirement to have sufficient decay heat removal capability using RHR loops; therefore, there is no change to the existing requirements and no change to the level of safety of facility operation.

This change, which allows the description of the design of the RHR loops to be maintained in the FSAR and the detailed description of the requirements for Operability of these systems to be maintained in the ITS Bases, is consistent with the approach used in NUREG-1431 for all Limiting Conditions for Operation (LCOs). This approach is acceptable because the requirements of 10 CFR 50.59, Changes, Tests and Experiments, and ITS 5.5.13, Technical Specifications (TS) Bases Control Program, are designed to assure that changes to the FSAR and ITS Bases do not result in changes to the Technical Specification requirements and do not result in significant increases in the probability or consequences of accidents previously evaluated, do not create the possibility of a new or different kind of accident, and do not result in a significant reduction in a margin of safety. Additionally, IP3 programs that implement FSAR changes in accordance with 10 CFR 50.59 and ITS Bases changes in accordance with ITS 5.5.13 require periodic submittal of FSAR and Bases changes to the NRC for review.

This change is a less restrictive administrative change with no impact on safety because no requirements are being deleted from Technical Specifications and an appropriate change control process and an appropriate level of regulatory oversight is maintained for the information being relocated out of the Technical Specifications.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.8:
"RCS Loops - MODE 5, Loops Not Filled"

PART 4:

No Significant Hazards Considerations
for
Changes between CTS and ITS
that are
Less Restrictive

No Significant Hazard Considerations for Changes that are Administrative, More Restrictive, and Removed Details are the same for all Packages. A Copy is included at the end of the Package.

NO SIGNIFICANT HAZARDS EVALUATION
ITS SECTION 3.4.8 - RCS Loops – MODE 5, Loops Not Filled

LESS RESTRICTIVE
("L.1" Labeled Comments/Discussions)

New York Power Authority has evaluated the proposed Technical Specification change identified as "Less Restrictive" in accordance with the criteria set forth in 10 CFR 50.92, and has determined that the proposed change does not involve a significant hazards consideration. The bases for the determination that the proposed changes do not involve a significant hazards consideration are discussed below.

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

   This change adds an allowance to requirements for decay heat removal in Mode 5 with loops not filled. This change allows one RHR loop to be inoperable for a period of 2 hours, provided the other RHR loop is Operable and in operation. This change will not result in a significant increase in the probability of an accident previously evaluated because not having a redundant RHR pump in standby is not the initiator of any event. This change will not result in a significant increase in the consequences of an accident previously evaluated because decay heat removal capability and forced circulation are maintained by the operating RHR loop, the duration without redundant decay heat removal capability is limited to 2 hours, and appropriate required actions are provided in the LCO if both methods of decay heat removal are lost.

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

   The proposed changes will not involve any physical changes to plant systems, structures, or components (SSC). The changes in normal plant operation are consistent with the current safety analysis assumptions because there is no change to the method of decay heat removal. Therefore, these changes will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

This change does not involve a significant reduction in a margin of safety because decay heat removal capability and forced circulation are maintained by the operating RHR loop, the duration of the period without redundant decay heat removal capability is limited to 2 hours, and appropriate required actions are provided in the LCO if both methods of decay heat removal are lost.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.8:
"RCS Loops - MODE 5, Loops Not Filled"

PART 5:

NUREG-1431
Annotated to show differences between
NUREG-1431 and ITS

Status of NUREG 1431 Generic Changes for ITS 3.4.8

This ITS Specification is based on NUREG-1431 Specification No. **3.4.8**
as modified by the following Generic Changes:

OG No.	TSTF No.	Generic Change Description	NRC STATUS	IP3 STATUS	JD No.
WOG-063	**153 R0**	CLARIFY EXCEPTION NOTES TO BE CONSISTENT WITH THE REQUIREMENT	Approved by NRC	Incorporated	**T.1**

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.8 RCS Loops—MODE 5, Loops Not Filled

<3.1.A.1d>
<3.3.A.7>

LCO 3.4.8 Two residual heat removal (RHR) loops shall be OPERABLE and one RHR loop shall be in operation. (not be in operation) (T.1)

---NOTES---

<DOC M.1>

1. All RHR pumps may be de-energized for ≤ 15 minutes when switching from one loop to another provided:

<3.1.A.1d>

   a. *The core outlet temperature is maintained > 10°F below saturation temperature.* (≥)

<3.1.A.1a>
<3.3.A.7>

   b. No operations are permitted that would cause a reduction of the RCS boron concentration; and

<DOC M.1>

   c. No draining operations to further reduce the RCS water volume are permitted.

<DOC L.1>

2. One RHR loop may be inoperable for ≤ 2 hours (up to) for surveillance testing provided that the other RHR loop is OPERABLE and in operation.

<3.1.A.1d>
<3.3.A.7>
<DOC A.5>

APPLICABILITY: MODE 5 with RCS loops not filled.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One RHR loop inoperable.	A.1 Initiate action to restore RHR loop to OPERABLE status.	Immediately

<3.3.A.7.a>

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
<3.3.A.7a> B. Required RHR loops inoperable. OR No RHR loop in operation.	B.1 Suspend all operations involving reduction in RCS boron concentration. AND B.2 Initiate action to restore one RHR loop to OPERABLE status and operation.	Immediately Immediately in

<3.1.A.1a>

PA.1

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
<DOC M.2> SR 3.4.8.1	Verify one RHR loop is in operation.	12 hours
<DOC M.2> SR 3.4.8.2	Verify correct breaker alignment and indicated power are available to the required RHR pump that is not in operation.	7 days

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.8 RCS Loops—MODE 5, Loops Not Filled

BASES

BACKGROUND

In MODE 5 with the RCS loops not filled, the primary function of the reactor coolant is the removal of decay heat generated in the fuel, and the transfer of this heat to the component cooling water via the residual heat removal (RHR) heat exchangers. The steam generators (SGs) are not available as a heat sink when the loops are not filled. The secondary function of the reactor coolant is to act as a carrier for the soluble neutron poison, boric acid.

In MODE 5 with loops not filled, only RHR pumps can be used for coolant circulation. The number of pumps in operation can vary to suit the operational needs. The intent of this LCO is to provide forced flow from at least one RHR pump for decay heat removal and transport and to require that two ~~paths~~ loops be available to provide redundancy for heat removal. PA.1

Insert: B 3.4-37-01

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. The flow provided by one RHR loop is adequate for heat removal and for boron mixing.

RCS loops in MODE 5 (loops not filled) ~~have been identified in the NRC Policy Statement as important contributors to risk reduction.~~

Insert: B 3.4-37-02

LCO

The purpose of this LCO is to require that at least two RHR loops be OPERABLE and one of these loops be in operation. An OPERABLE loop is one that has the capability of transferring heat from the reactor coolant at a controlled rate. Heat cannot be removed via the RHR System unless forced flow is used. A minimum of one running RHR pump meets the LCO requirement for one loop in operation. An additional RHR loop is required to be OPERABLE to meet ~~single failure~~ redundancy considerations. DB.1

(continued)

INSERT: B 3.4-37-01

Each RHR loop consists of one RHR pump and one RHR heat exchanger as well as associated piping and valves to transfer decay heat between the RHR heat exchanger and the core. Although either RHR heat exchanger may be credited for either RHR loop, one RHR heat exchanger must be OPERABLE for each OPERABLE RHR loop. Separate RHR loops may include common piping and valves.

INSERT: B 3.4-37-02

satisfy Criterion 4 of 10 CFR 50.36.

BASES

not be in operation

T.1

LCO (continued)

Note 1 permits all RHR pumps to be de-energized for ≤ 15 minutes when switching from one loop to another. The circumstances for stopping both RHR pumps are to be limited to situations when the outage time is short (and core outlet temperature is maintained ≥ 10°F below saturation temperature). The Note prohibits boron dilution or draining operations when RHR forced flow is stopped.

Note 2 allows one RHR loop to be inoperable for a period of ≤ 2 hours, provided that the other loop is OPERABLE and in operation. This permits periodic surveillance tests to be performed on the inoperable loop during the only time when these tests are safe and possible when in Mode 5.

PA.1

An OPERABLE RHR loop is comprised of an OPERABLE RHR pump capable of providing forced flow to an OPERABLE RHR heat exchanger. RHR pumps are OPERABLE if they are capable of being powered and are able to provide flow if required.

APPLICABILITY

In MODE 5 with loops not filled, this LCO requires core heat removal and coolant circulation by the RHR System.

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 3.4.7, "RCS Loops—MODE 5, Loops Filled";
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation—High Water Level" (MODE 6); and
LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation—Low Water Level" (MODE 6).

ACTIONS

A.1

If only one RHR loop is OPERABLE and in operation, redundancy for RHR is lost. Action must be initiated to restore a second loop to OPERABLE status. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

loops

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If no required RHR loops are OPERABLE or in operation, when required RHR loops are not OPERABLE or in operation, except during conditions permitted by Note 1, all operations involving a reduction of RCS boron concentration must be suspended and action must be initiated immediately to restore an RHR loop to OPERABLE status and operation. Boron dilution requires forced circulation for uniform dilution. PA.1 ~~and~~ the margin to criticality must not be reduced ~~in this type of operation~~. The immediate Completion Time reflects the importance of maintaining operation for heat removal. The action to restore must continue until one loop is restored to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.8.1

This SR requires verification every 12 hours that one loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RHR loop performance.

SR 3.4.8.2

Verification that the required number of pumps are OPERABLE ensures that additional pumps can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the required pumps. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES

None.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.8:
"RCS Loops - MODE 5, Loops Not Filled"

PART 6:

Justification of Differences between

NUREG-1431 and IP3 ITS

JUSTIFICATION OF DIFFERENCES FROM NUREG-1431
ITS SECTION 3.4.8 - RCS Loops – MODE 5, Loops Not Filled

RETENTION OF EXISTING REQUIREMENT (CURRENT LICENSING BASIS)

None

PLANT-SPECIFIC WORDING PREFERENCE OR MINOR EDITORIAL IMPROVEMENT

PA.1 Corrected typographical error or made a minor editorial improvement to improve clarity and ensure requirements are fully understood and consistently applied. There are no technical changes to requirements as specified in NUREG 1431, Rev. 1; therefore, this change is not a significant or generic deviation from NUREG 1431, Rev 1.

PLANT-SPECIFIC DIFFERENCE IN THE DESIGN OR DESIGN BASIS

DB.1 Design or implementation details are incorporated or revised as necessary to more precisely describe IP3 current design or practice. These changes are intended to describe the design, improve clarity, or ensure requirements are fully understood and consistently applied. Unless identified and described blow, these changes are self-explanatory. A detailed description of the design, accident analysis assumptions, and Operability requirements are incorporated into the IP3 ITS Bases. These changes maintain the IP3 current licensing basis except as identified and justified in the CTS/ITS discussion of changes.

DIFFERENCE BASED ON A GENERIC CHANGE TRAVELER FOR NUREG-1431

T.1 This change incorporates Generic Change TSTF-153, Rev.0 (WOG-63) which rewords notes taking exception to LCO requirements to be consistent with the wording of the requirement. Specifically, the LCO contains a Note taking exception to the LCO requirement for pumps to "be in operation" but states the exception as "may be de-energized." Therefore, each Note is revised to provide wording consistent with the requirement being excepted. This generic change to NUREG-1431, Rev 1, is approved by the NRC.

DIFFERENCE FOR ANY REASON OTHER THAN ABOVE

None

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.9:

"Pressurizer"

PART 1:

Indian Point 3
Improved Technical Specifications and Bases

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.9 Pressurizer

LCO 3.4.9 The pressurizer shall be OPERABLE with:

a. Pressurizer water level ≤ 92%; and

b. Two groups of pressurizer heaters OPERABLE with the capacity of each group ≥ 150 kW with each group powered from a different safeguards power train.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Pressurizer water level not within limit.	A.1	Be in MODE 3 with reactor trip breakers open.	6 hours
	AND		
	A.2	Be in MODE 4.	12 hours
B. One required group of pressurizer heaters inoperable.	B.1	Restore required group of pressurizer heaters to OPERABLE status.	72 hours
C. Required Action and associated Completion Time of Condition B not met.	C.1	Be in MODE 3.	6 hours
	AND		
	C.2	Be in MODE 4.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.9.1	Verify pressurizer water level is ≤ 92%.	12 hours
SR 3.4.9.2	Verify capacity of each required group of pressurizer heaters is ≥ 150 kW.	24 months

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.9 Pressurizer

BASES

BACKGROUND

The pressurizer provides a point in the RCS where liquid and vapor are maintained in equilibrium under saturated conditions for pressure control purposes to prevent bulk boiling in the remainder of the RCS. Key functions include maintaining required primary system pressure during steady state operation, and limiting the pressure changes caused by reactor coolant thermal expansion and contraction during normal load transients.

The pressure control components addressed by this LCO include the pressurizer water level, the required heaters, and emergency power supplies. Pressurizer safety valves and pressurizer power operated relief valves are addressed by LCO 3.4.10, "Pressurizer Safety Valves," and LCO 3.4.11, "Pressurizer Power Operated Relief Valves (PORVs)," respectively.

The intent of the LCO is to ensure that a steam bubble exists in the pressurizer prior to power operation to minimize the consequences of potential overpressure transients. The presence of a steam bubble is consistent with analytical assumptions. Relatively small amounts of noncondensible gases can inhibit the condensation heat transfer between the pressurizer spray and the steam, and diminish the spray effectiveness for pressure control.

Electrical immersion heaters, located in the lower section of the pressurizer vessel, keep the water in the pressurizer at saturation temperature and maintain a constant operating pressure. A minimum required available capacity of pressurizer heaters ensures that the RCS pressure can be maintained. The capability to maintain and control system pressure is important for maintaining subcooled conditions in the RCS and ensuring the capability to remove core decay heat by either forced or natural circulation of reactor coolant. Unless adequate heater capacity is available, the hot, high pressure condition cannot be maintained indefinitely and still provide the required subcooling margin in the primary system. Inability to control the system pressure and maintain subcooling under conditions of natural circulation flow in the primary system could lead to a loss of

BASES

BACKGROUND (Continued)

single phase natural circulation and decreased capability to remove core decay heat.

Pressurizer heaters are powered from either the offsite source or the diesel generators (DGs) through the four 480V vital buses as follows: bus 2A (DG 31) supports 485 kW of pressurizer heaters; bus 3A (DG 31) supports 555 kW of pressurizer heaters; bus 5A (DG 33) supports 485 kW of pressurizer heaters; and, bus 6A (DG 32) supports 277 kW of pressurizer heaters.

APPLICABLE SAFETY ANALYSES

In MODES 1, 2, and 3, the LCO requirement for a steam bubble is reflected implicitly in the accident analyses. 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 FSAR (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. 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 requirement for the pressurizer to be OPERABLE with water level less than or equal to 92%, ensures that a steam bubble exists. Limiting the LCO maximum operating water level preserves the steam space for pressure control. The LCO has been

BASES

LCO (continued)

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, capable of being powered from either the offsite power source or the emergency power supply. Each of the 2 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 is sufficient to maintain pressure and is dependent on the heat losses.

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.

BASES

ACTIONS

A.1 and A.2

Pressurizer water level control malfunctions or other plant evolutions may result in a pressurizer water level above the nominal upper limit, even with the plant at steady state conditions. Normally the plant will trip in this event since the upper limit of this LCO is the same as the Pressurizer Water Level – High Trip.

If the pressurizer water level is not within the limit, action must be taken to place the plant in a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to MODE 3, with the reactor trip breakers open, within 6 hours and to MODE 4 within 12 hours. This takes the unit out of the applicable MODES.

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.

B.1

If one required group of pressurizer heaters is inoperable, restoration is required within 72 hours. The Completion Time of 72 hours is reasonable considering that the redundant heater group is still available and the low probability of an event during this period. Pressure control may be maintained during this time using remaining heaters.

C.1 and C.2

If one group of pressurizer heaters are inoperable and cannot be restored in the allowed Completion Time of Required Action B.1, 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 MODE 3 within 6 hours and to MODE 4 within 12 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

SURVEILLANCE REQUIREMENTS

SR 3.4.9.1

This SR requires that during steady state operation, pressurizer level is maintained below the nominal upper limit to provide a minimum space for a steam bubble. The Surveillance is performed by observing the indicated level. The Frequency of 12 hours has been shown by operating practice to be sufficient to regularly assess level for any deviation and verify that operation is within safety analyses assumptions of ensuring that a steam bubble exists in the pressurizer. Alarms are also available for early detection of abnormal level indications.

SR 3.4.9.2

The SR is satisfied when the power supplies are demonstrated to be capable of producing the minimum power and the associated pressurizer heaters are verified to be at their design rating. This may be done separately by testing the power supply output and by performing an electrical check on heater element continuity and resistance. The Frequency of 24 months is considered adequate to detect heater degradation and has been shown by operating experience to be acceptable.

REFERENCES

1. FSAR, Section 14.

2. NUREG-0737, November 1980.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.9:
"Pressurizer"

PART 2:

CURRENT TECHNICAL SPECIFICATION PAGES

Annotated to show differences between CTS and ITS

CTS pages and associated TSCRs annotated for this ITS Specification :

CTS Page No.	Effective Amendment	Annotated Amendment	TSCR No.	TSCR Description	ITS Status of TSCR
3.1-4	170	170	No TSCRs	No TSCRs for this Page	N/A
3.1-8	179	179	No TSCRs	No TSCRs for this Page	N/A
3.1-25	149	149	No TSCRs	No TSCRs for this Page	N/A

A.1 A.2

Add SR 3.4.9.2 — M.4

SEE ITS 3.4.11

2. Safety Valves

a. At least one pressurizer code safety valve shall be operable, or an opening greater than or equal to the size of one code safety valve flange to allow for pressure relief, whenever the reactor head is on the vessel except for hydrostatically testing the RCS in accordance with Section XI of the ASME Boiler and Pressure Vessel Code.

b. All pressurizer code safety valves shall be operable whenever the reactor is above the cold shutdown condition except during reactor coolant system hydrostatic tests and/or safety valve settings.

c. The pressurizer code safety valve lift setting shall be set at 2485 psig with ±1% allowance for error.

LCO 3.4.9 Applicability LCO 3.4.9.b

~~3.~~ Pressurizer Heaters

Mode 1, 2, 3 — M.2

~~Whenever the reactor is above the hot shutdown condition,~~ the pressurizer shall be operable with at least 150 kw of pressurizer heaters.

Two groups each with — M.1

a. With ~~less than 150 kw~~ one group of pressurizer heaters not operable, restore the required inoperable heaters within 72 hours or be in at least hot shutdown within an additional 6 hours and Mode 4 in 12 hr — M.2

4. Power Operated Relief Valves

Whenever the reactor coolant system is above 400°F, the power operated relief valves (PORVs) shall be operable or their associated block valves closed.

a. If the block valve is closed because of an inoperable PORV, the control power for the block valve must be removed.

b. If the above conditions cannot be satisfied within 1 hour, be in at least hot shutdown within 6 hours and in cold shutdown within the following 30 hours.

SEE ITS 3.4.11

5. Power Operated Relief Block Valves

Whenever the reactor coolant system is above 400°F, the motor operated block valves shall be operable or closed.

a. If the block valve is inoperable, the control power is to be removed.

b. If the above conditions cannot be satisfied within 1 hour be in at least hot shutdown within the following 30 hours.

6. Deleted

A.1

The requirement that 150 kw of pressurizer heaters and their associated controls be capable of being supplied electrical power from an emergency bus provides assurance that these heaters can be energized during a loss of offsite power condition to maintain natural circulation at hot shutdown.

The power operated relief valves (PORVs) operate to relieve RCS pressure below the setting of the pressurizer code safety valves. These relief valves have remotely operated block valves to provide a positive shutoff capability should a relief valve become inoperable. The electrical power for both the relief valves and the block valves is capable of being supplied from an emergency power source to ensure the ability to seal off possible RCS leakage paths.

Reactor vessel head vents are provided to exhaust noncondensible gases and/or steam from the primary system that could inhibit natural circulation core cooling. The OPERABILITY of at least one reactor vessel head vent path ensures that capability exists to perform this function.

The valve redundancy of the reactor coolant system vent paths serves to minimize the probability of inadvertent or irreversible actuation while ensuring that a single failure of a vent valve power supply or control system does not prevent isolation of the vent path.

The function, capabilities, and testing requirements of the reactor coolant system vent systems are consistent with the requirements of Item II.B.1 of NUREG-0737, "Clarification of TMI Action Plan Requirements," November, 1980.

The OPS is designed to relieve the RCS pressure for certain unlikely incidents to prevent the peak RCS pressure from exceeding the 10 CFR 50, Appendix G, limits. "Arming" means that the motor operated valve (MOV) is in the open position. This can be accomplished either automatically by the OPS when the RCS temperature is less than or equal to 332°F or manually by the control room operator.

C. MINIMUM CONDITIONS FOR CRITICALITY

SEE ITS 3.1.3 ITS 3.1.8 ITS 3.4.2

1. Except during low power physics test, the reactor shall not be made critical at any temperature above which the moderator temperature coefficient is positive.

2. This section intentionally deleted.

3. At all times during critical operation, the lowest loop T_{avg} shall be no lower than 540 °F.
   a. If T_{avg} is less than 540°F when the reactor is critical, restore T_{avg} to $\geq$ 540 °F within 15 minutes or be in hot shutdown within the following 15 minutes.

LCO 3.4.9 Applicability

4. The reactor shall be maintained subcritical by at least 1% $\frac{\Delta k}{k}$ until normal water level is established in the pressurizer.

Mode 1, 2, 3 — M.

≤92% — L.1

Basis

During the early part of the initial fuel cycle, the moderator temperature coefficient is calculated to be slightly positive at coolant temperatures below the power operating range. [1] [2] The moderator coefficient at low temperatures will be most positive at the beginning of life of the fuel cycle, when the boron concentration in the coolant is the greatest. Later in the life of the fuel cycle, the boron concentration in the coolant will be lower and the moderator coefficient will be either less positive or will be negative. At all times, the moderator coefficient is negative in the power operating range. [1] [2] Suitable physics measurements of moderator coefficient of reactivity will be made as part of the startup program to verify analytic predictions. — A.1

The requirement that the reactor is not to be made critical when the moderator coefficient is positive has been imposed to prevent any unexpected power excursion during normal operations as a result of an increase in moderator temperature. This requirement is waived during low power physics tests to permit measurement of reactor moderator coefficient and other physics design parameters of interest. During physics tests, special operating precautions will be taken.

The requirement that the reactor is not to be made critical except when T_{avg} is $\geq$ 540 °F provides assurance that an overpressure event will not occur whenever the reactor vessel is in the nil-ductility temperature range and that the reactor is operated within the bounds of the safety analyses. The safety analyses, which assume a critical temperature of 547 °F, are applicable for critical temperatures as low as 540 °F. Heatup to this temperature will be accomplished by operating the reactor coolant pumps. The Surveillance requirement to support this specification is provided in Table 4.1-1 item no. 4.

The requirement for bubble formation in the pressurizer when the reactor has passed the threshold of 1% subcriticality will assure that the reactor coolant not be solid when criticality is achieved.

References:

1. FSAR Table 3.2-1
2. FSAR Figure 3.2-9

Add Condition A and associated Req. Acts — M.3

Add SR 3.4.9.1 — M.4

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.9:
"Pressurizer"

PART 3:

DISCUSSION OF CHANGES

Differences between CTS and ITS

DISCUSSION OF CHANGES
ITS SECTION 3.4.9 - Pressurizer

ADMINISTRATIVE

A.1 In the conversion of the Indian Point Unit 3 Current Technical Specifications (CTS) to the plant specific Improved Technical Specifications (ITS) certain wording preferences or conventions are adopted which do not result in technical changes (either actual or interpretational). Additionally, editorial changes, reformatting, and revised numbering are adopted to make ITS consistent with the conventions in NUREG-1431, Standard Technical Specifications, Westinghouse Plants, Rev. 1, i.e., the improved Standard Technical Specifications.

The CTS Bases are deleted and replaced with comprehensive ITS Bases designed to support interpretation and implementation of the associated Technical Specifications. The Bases explain, clarify, and document the reasons (i.e., bases) for the associated Technical Specifications, and reflect the IP3 plant specific design, analyses, and licensing basis. In accordance with 10 CFR 50.36(a), the ITS Bases are included with the proposed ITS conversion application; however, deletion of the CTS Bases and the adoption of the ITS Bases is an administrative change with no impact on safety.

A.2 CTS Limiting Conditions for Operation (LCOs) and Surveillance Requirements (SRs) include statements of the objective and the applicability. The CTS statements of objective and applicability are deleted because these statements do not establish any requirements and do not provide any guidance for the application of CTS requirements. Therefore, deletion of these statements has no significant adverse impact on safety.

MORE RESTRICTIVE

M.1 CTS 3.1.A.3 requires at least 150 kW of pressurizer heaters that are capable of being energized during a loss of offsite power condition so that natural circulation can always be maintained during hot shutdown. CTS 3.1.A.3.a provides an allowable out of service time of 72 hours if the required heater capacity is not Operable.

ITS LCO 3.4.9 requires 2 groups of pressurizer heaters and that each of these groups must have a capacity of 150 kW and each group must be powered from a different safeguards power train (i.e., diesel generator (DG)). In conjunction with this change, LCO 3.4.9. Required Action B.1, provides an allowable out of service time of 72 hours if one of the two required heater groups is not Operable. Furthermore, although not stated as an Action for ITS LCO 3.4.9, entry into LCO 3.0.3 is required if neither group of pressurizer heaters is Operable.

This change is needed because 150 kW of pressurizer heater capacity must be available in Modes 1, 2 and 3 (See ITS 3.4.9, DOC M.2) to support decay heat removal using natural circulation following a loss of offsite power. Requiring 2 groups of pressurizer heaters and that each group is powered from a separate DG ensures that the single failure of a DG will not result in a loss of the required pressurizer heater capacity.

This more restrictive change is acceptable because it does not introduce any operation that is un-analyzed while ensuring the required pressurizer heater capacity will be available following a loss of offsite power with concurrent failure of one DG. Therefore, this change has no adverse impact on safety.

M.2 CTS 3.1.A.3 specifies that the pressurizer must be Operable with the specified heater capacity whenever the reactor is above the hot shutdown condition (Modes 1 and 2). CTS 3.1.C.4 requires that the pressurizer normal water level must be maintained (See ITS 3.4.9, DOC L.1) whenever the reactor is not subcritical by at least 1% Δk (Modes 1 and 2).

ITS LCO 3.4.9, Applicability, requires the pressurizer Operable with the level below the specified maximum and with required heater capacity whenever the plant is in Modes 1, 2 and 3. In conjunction with this change, ITS 3.4.9, Required Actions A.2 and C.2, are added to require that the plant be placed outside Applicability (i.e., the plant must be placed in Mode 2) if requirements are not met.

This change, requiring pressurizer Operability in Mode 3, is needed because pressurizer Operability in Mode 3 will prevent solid water operation during heatup and cooldown and during other operational

perturbations (e.g., RCP starts) that could cause rapid pressure increases if the pressurizer is solid.

This change is acceptable because it does not introduce any operation that is un-analyzed while requiring that the pressurizer be available for pressure control during heatup and cooldown and during other operational perturbations (e.g., RCP starts) that could cause rapid pressure increases if the pressurizer is solid. Therefore, this change has no adverse impact on safety.

M.3 CTS 3.1.C.4 requires that the pressurizer normal water level must be maintained (See ITS 3.4.9, DOC L.1) whenever the reactor is not subcritical by at least 1% Δk (Modes 1 and 2); however, no Actions are specified if this requirement is not met (although if pressurizer water level reached the ITS LCO 3.4.9 limit, a reactor trip on Pressurizer Water Level-High would occur).

ITS LCO 3.4.9, Required Actions A.1 and A.2, are added to require that a reactor must be placed in Mode 4 within 12 hours if pressurizer water level cannot be maintained within the specified limit.

This change is needed to supplement the reactor trip on Pressurizer Water Level-High and require that the plant be placed outside the LCO Applicability (i.e., the plant must be placed in Mode 4) in addition to the reactor shutdown caused by the reactor trip on Pressurizer Water Level-High to prevent solid water operation during heatup and cooldown and during other operational perturbations (e.g., RCP starts) that could cause rapid pressure increases if the pressurizer is solid in Mode 3. This change is acceptable because it does not introduce any operation that is un-analyzed. Therefore, this change has no adverse impact on safety.

M.4 CTS 3.1.A.3 requires a specified pressurizer heater capacity must be available whenever the reactor is above the hot shutdown condition (See ITS 3.4.9, DOC M.2). CTS 3.1.C.4 requires that a specified pressurizer water level must be maintained (See ITS 3.4.9, DOC L.1) whenever the reactor is not subcritical by at least 1% Δk (See ITS 3.4.9, DOC M.2).

However, no surveillance requirements are established to periodically verify these requirements are met.

ITS SR 3.4.9.1 is added to verify every 12 hours that pressurizer level is within the required limit. The Frequency of 12 hours is considered adequate because the limit is enforced by the reactor trip on Pressurizer Water Level-High.

ITS SR 3.4.9.2 is added to demonstrated every 24 months that the specified pressurizer heater capacity is available by checking the power supply output and by performing an electrical check on heater element continuity and resistance. The Frequency of 24 months is considered adequate to detect heater degradation because the have exhibited a high degree of reliability and these heaters are used during normal operation.

These changes are needed to require periodic verification that the requirements of ITS LCO 3.4.9 are met.

These changes are acceptable because they do not introduce any operation that is un-analyzed while requiring periodic verification that pressurizer operation is within specified limits. Therefore, this change has no adverse impact on safety.

LESS RESTRICTIVE

L.1 CTS 3.1.C.4 requires normal water level be established in the pressurizer prior to reactor criticality (See ITS 3.4.9, DOC M.2).

ITS LCO 3.4.9 requires that pressurizer water level be less than or equal to 92% in Mode 1, 2 and 3 (See ITS 3.4.9, DOC M.2).

Replacing the requirement to maintain pressurizer level in the normal range with a requirement to maintain pressurizer level less than or equal to 92% is needed and is acceptable because the LCO is only intended to limit maximum operating water level to preserve a steam space for pressure control. This 92% limit includes margin for instrument error and transient level overshoot beyond the reactor trip

setting so that the associated reactor trip function prevents the water level from reaching the pressurizer safety valves. Additionally, the upper limit on pressurizer level ensures 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. Therefore, this change has no significant adverse impact on safety.

REMOVED DETAIL

None

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.9:
"Pressurizer"

PART 4:

No Significant Hazards Considerations
for
Changes between CTS and ITS
that are
Less Restrictive

No Significant Hazard Considerations for Changes that are Administrative, More Restrictive, and Removed Details are the same for all Packages. A Copy is included at the end of the Package.

NO SIGNIFICANT HAZARDS EVALUATION
ITS SECTION 3.4.9 - Pressurizer

LESS RESTRICTIVE
("L.1" Labeled Comments/Discussions)

New York Power Authority has evaluated the proposed Technical Specification change identified as "Less Restrictive" in accordance with the criteria set forth in 10 CFR 50.92, and has determined that the proposed change does not involve a significant hazards consideration. The bases for the determination that the proposed changes do not involve a significant hazards consideration are discussed below.

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

   This change replaces the requirement to maintain pressurizer level in the normal range when critical to a requirement to maintain pressurizer water level less than or equal to 92%.

   This change will not result in a significant increase in the probability or consequences of an accident previously evaluated because the LCO is intended only to limit maximum operating water level to preserve a the steam space for pressure control. The upper limit for pressurizer level, in conjunction with the high pressurizer water level reactor trip, protects the pressurizer safety valves against water relief. This limit allows margin for instrument error and transient level overshoot beyond the reactor trip setting so that the reactor trip function prevents the water level from reaching the pressurizer safety valves. Additionally, the upper limit on pressurizer level ensures 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.

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

   The proposed changes will not involve any physical changes to plant systems, structures, or components (SSC). The changes in normal Plant operation are consistent with the current safety analysis assumptions because pressurizer level will be maintained in the normal operating

range. This change is consistent with the high pressurizer water level reactor trip that protects the pressurizer safety valves against water relief. Therefore, these changes will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

This change does not involve a significant reduction in a margin of safety because the LCO is intended only to limit maximum operating water level to preserve a the steam space for pressure control. The upper limit for pressurizer level, in conjunction with the high pressurizer water level reactor trip, protects the pressurizer safety valves against water relief. This limit allows margin for instrument error and transient level overshoot beyond the reactor trip setting so that the reactor trip function prevents the water level from reaching the pressurizer safety valves. Additionally, the upper limit on pressurizer level ensures 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.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.9:
"Pressurizer"

PART 5:

NUREG-1431
Annotated to show differences between
NUREG-1431 and ITS

Status of NUREG 1431 Generic Changes for ITS 3.4.9

This ITS Specification is based on NUREG-1431 Specification No. **3.4.9**
as modified by the following Generic Changes:

OG No.	TSTF No.	Generic Change Description	NRC STATUS	IP3 STATUS	JD No.
WOG-019	**093 R0**	CHANGE THE FREQUENCY OF PRESSURIZER HEATER TESTING FROM 92 DAYS TO [18] MONTHS	See Next Rev.	Not Incorporated	**N/A**
WOG-019 R1	**093 R1**	CHANGE THE FREQUENCY OF PRESSURIZER HEATER TESTING FROM 92 DAYS TO [18] MONTHS	See Next Rev	Not Incorporated	**N/A**
WOG-019 R3	**093 R3**	CHANGE THE FREQUENCY OF PRESSURIZER HEATER TESTING FROM 92 DAYS TO [18] MONTHS	Approved by NRC	Incorporated. CLB is no testing.	**T.1**
WOG-020	**094 R0**	REMOVE NUMBER OF REQUIRED PRESSURIZER HEATER GROUPS FROM PRESSURIZER LCO	See Next Rev	Not Incorporated	**N/A**
WOG-020 R1	**094 R1**	REMOVE NUMBER OF REQUIRED PRESSURIZER HEATER GROUPS FROM PRESSURIZER LCO	Approved by NRC	Not Incorporated	**N/A**

Technical Specification 3.4.9: "Pressurizer"

WOG-046	**087 R2**	REVISE "RTBS OPEN" & "CRDM DE-ENERGIZED" ACTIONS TO "INCAPABLE OF ROD WITHDRAWAL"	Approved by NRC	Not Incorporated	**N/A**
WOG-068	**162 R0**	MAXIMUM PRESSURIZER WATER LEVEL LIMIT BASES	Approved by NRC	Incorporated	**T.2**

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.9 Pressurizer

<3.1.A.3> LCO 3.4.9 The pressurizer shall be OPERABLE with:

<3.1.C.4><DOC L.1> a. Pressurizer water level ≤ ~~[92]~~ 150%; and

<3.1.A.3><DOC M.1> b. Two groups of pressurizer heaters OPERABLE with the capacity of each group ≥ ~~[125]~~ kW ~~[and capable of being powered from an emergency power supply]~~. DB1

Insert: 3.4-19-01

<3.1.A.3> <3.1.C.4> <DOC M.2> APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
<DOC M.3> A. Pressurizer water level not within limit.	A.1 Be in MODE 3 with reactor trip breakers open.	6 hours
	AND	
<DOC M.2>	A.2 Be in MODE 4.	12 hours
<3.1.A.3.a> <DOC M.1> B. One required group of pressurizer heaters inoperable.	B.1 Restore required group of pressurizer heaters to OPERABLE status.	72 hours
<3.1.A.3.a> C. Required Action and associated Completion Time of Condition B not met.	C.1 Be in MODE 3.	6 hours
	AND	
<DOC M.2>	C.2 Be in MODE 4.	12 hours

INSERT: 3.4-19-01

with each group powered from a different safeguards power train.

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE		FREQUENCY
⟨DOC M.4⟩	SR 3.4.9.1	Verify pressurizer water level is ≤ [92]%.	12 hours
⟨DOC M.4⟩	SR 3.4.9.2	Verify capacity of each required group of pressurizer heaters is ≥ [125] kW. 150	~~92 days~~ 24 months (T.1)
	~~SR 3.4.9.3~~	~~Verify required pressurizer heaters are capable of being powered from an emergency power supply.~~	~~[18] months~~

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.9 Pressurizer

BASES

BACKGROUND

The pressurizer provides a point in the RCS where liquid and vapor are maintained in equilibrium under saturated conditions for pressure control purposes to prevent bulk boiling in the remainder of the RCS. Key functions include maintaining required primary system pressure during steady state operation, and limiting the pressure changes caused by reactor coolant thermal expansion and contraction during normal load transients.

The pressure control components addressed by this LCO include the pressurizer water level, the required heaters, and their controls and emergency power supplies. Pressurizer safety valves and pressurizer power operated relief valves are addressed by LCO 3.4.10, "Pressurizer Safety Valves," and LCO 3.4.11, "Pressurizer Power Operated Relief Valves (PORVs)," respectively.

The intent of the LCO is to ensure that a steam bubble exists in the pressurizer prior to power operation to minimize the consequences of potential overpressure transients. The presence of a steam bubble is consistent with analytical assumptions. Relatively small amounts of noncondensible gases can inhibit the condensation heat transfer between the pressurizer spray and the steam, and diminish the spray effectiveness for pressure control.

Electrical immersion heaters, located in the lower section of the pressurizer vessel, keep the water in the pressurizer at saturation temperature and maintain a constant operating pressure. A minimum required available capacity of pressurizer heaters ensures that the RCS pressure can be maintained. The capability to maintain and control system pressure is important for maintaining subcooled conditions in the RCS and ensuring the capability to remove core decay heat by either forced or natural circulation of reactor coolant. Unless adequate heater capacity is available, the hot, high pressure condition cannot be maintained indefinitely and still provide the required subcooling margin in the primary system. Inability to control the system pressure and maintain subcooling under conditions of natural circulation flow in the primary system could lead to

(continued)

BASES

Insert: B 3.4-41-01

BACKGROUND (continued)

a loss of single phase natural circulation and decreased capability to remove core decay heat.

APPLICABLE SAFETY ANALYSES

In MODES 1, 2, and 3, the LCO requirement for a steam bubble is reflected implicitly in the accident analyses. 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.

Insert: B 3.4-41-02

Safety analyses presented in the FSAR (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.

10 CFR 50.36

The maximum pressurizer water level limit satisfies Criterion 2 of ~~the NRC Policy Statement~~. 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.

T.2

LCO

water level less than or equal to

The LCO requirement for the pressurizer to be OPERABLE with ~~a water volume < [1240] cubic feet, which is equivalent to~~ [92]%, ensures that a steam bubble exists. 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.

150

The LCO requires two groups of OPERABLE pressurizer heaters, each with a capacity ≥ [125] kW, capable of being powered from either the offsite power source or the emergency power supply. 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

Insert: B 3.4-41-03

(continued)

INSERT: B 3.4-41-01

DB.1

Pressurizer heaters are powered from either the offsite source or the diesel generators (DGs) through the four 480 V vital buses as follows: bus 2A (DG 31) supports 485 kW of pressurizer heaters; bus 3A (DG 31) supports 555 kW of pressurizer heaters; bus 5A (DG 33) supports 485 kW of pressurizer heaters; and, bus 6A (DG 32) supports 277 kW of pressurizer heaters.

INSERT: B 3.4-41-02

PA.1

, which ensures that a steam bubble exists in the pressurizer,

INSERT: B 3.4-41-03

DB.1

Each of the 2 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.

BASES

LCO (continued)

conditions, a wide margin to subcooling can be obtained in the loops. The ~~exact design~~ value of 125 kW ~~is derived~~ from the ~~use of seven heaters rated at 17.9 kW each. The~~ ~~amount needed~~ is sufficient to maintain pressure and is dependent on the heat losses.

150

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.

ACTIONS

A.1 and A.2

Pressurizer water level control malfunctions or other plant evolutions may result in a pressurizer water level above the nominal upper limit, even with the plant at steady state conditions. Normally the plant will trip in this event since the upper limit of this LCO is the same as the Pressurizer Water Level—High Trip.

If the pressurizer water level is not within the limit, action must be taken to ~~restore the plant to operation within the bounds of the safety analyses~~. To achieve this status, the unit must be brought to MODE 3, with the reactor trip breakers open, within 6 hours and to MODE 4 within 12 hours. This takes the unit out of the applicable MODES.

Insert: B3.4-42-01

T.2

(continued)

INSERT: B 3.4-42-01

place the plant in a MODE in which the LCO does not apply.

BASES

ACTIONS

A.1 and A.2 (continued)

and restores the unit to operation within the bounds of the safety analyses. T.2

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.

B.1

Insert: B3.4-43-01

If one required group of pressurizer heaters is inoperable, restoration is required within 72 hours. The Completion Time of 72 hours is reasonable considering the anticipation that a demand caused by loss of offsite power would be unlikely in this period. Pressure control may be maintained during this time using normal station powered heaters.

remaining

C.1 and C.2

If one group of pressurizer heaters are inoperable and cannot be restored in the allowed Completion Time of Required Action B.1, 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 MODE 3 within 6 hours and to MODE 4 within 12 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 3.4.9.1

This SR requires that during steady state operation, pressurizer level is maintained below the nominal upper limit to provide a minimum space for a steam bubble. The Surveillance is performed by observing the indicated level. The Frequency of 12 hours corresponds to verifying the parameter each shift. The 12 hour interval has been shown by operating practice to be sufficient to regularly assess level for any deviation and verify that operation is within

(continued)

INSERT: B 3.4-43-01

that the redundant heater group is still available and the low probability of an event during this period.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.9.1 (continued)

safety analyses assumptions. Alarms are also available for early detection of abnormal level indications. T.2

Insert: B3.4-44-01

SR 3.4.9.2

separately

The SR is satisfied when the power supplies are demonstrated to be capable of producing the minimum power and the associated pressurizer heaters are verified to be at their design rating. This may be done by testing the power supply output and by performing an electrical check on heater element continuity and resistance. The Frequency of 92 days is considered adequate to detect heater degradation and has been shown by operating experience to be acceptable.

24 months

~~SR 3.4.9.3~~

~~This SR is not applicable if the heaters are permanently powered by Class 1E power supplies.~~

~~This Surveillance demonstrates that the heaters can be manually transferred from the normal to the emergency power supply and energized. The Frequency of 18 months is based on a typical fuel cycle and is consistent with similar verifications of emergency power supplies.~~

REFERENCES

1. FSAR, Section ~~13~~. 14
2. NUREG-0737, November 1980.

INSERT: B 3.4-44-01

of ensuring that a steam bubble exists in the pressurizer

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.9:
"Pressurizer"

PART 6:

Justification of Differences between

NUREG-1431 and IP3 ITS

JUSTIFICATION OF DIFFERENCES FROM NUREG-1431
ITS SECTION 3.4.9 - Pressurizer

RETENTION OF EXISTING REQUIREMENT (CURRENT LICENSING BASIS)

None

PLANT-SPECIFIC WORDING PREFERENCE OR MINOR EDITORIAL IMPROVEMENT

PA.1 Corrected typographical error or made a minor editorial improvement to improve clarity and ensure requirements are fully understood and consistently applied. There are no technical changes to requirements as specified in NUREG 1431, Rev. 1; therefore, this change is not a significant or generic deviation from NUREG 1431, Rev 1.

PLANT-SPECIFIC DIFFERENCE IN THE DESIGN OR DESIGN BASIS

DB.1 Design or implementation details are incorporated or revised as necessary to more precisely describe IP3 current design or practice. These changes are intended to describe the design, improve clarity, or ensure requirements are fully understood and consistently applied. Unless identified and described blow, these changes are self-explanatory. A detailed description of the design, accident analysis assumptions, and Operability requirements are incorporated into the IP3 ITS Bases. These changes maintain the IP3 current licensing basis except as identified and justified in the CTS/ITS discussion of changes.

DIFFERENCE BASED ON A GENERIC CHANGE TRAVELER FOR NUREG-1431

T.1 This change incorporates Generic Change TSTF-93 (WOG-19), which changes the frequency of pressurizer heater testing (SR 3.4.9.2)from 92 days to 24 months. This change is acceptable because the heaters are normally in operation and significant degradation will be detected. This change is in accordance with Section 6.6 of NUREG-1366.

T.2 This change incorporates Generic Change TSTF-162 (WOG-68), which explains the bases for the maximum pressurizer water level limit. This change is needed to properly explain that the maximum pressurizer water

level limit is based on ensuring that a steam bubble exists in the pressurizer. The maximum pressurizer water level is not explicitly credited in any safety analysis.

DIFFERENCE FOR ANY REASON OTHER THAN ABOVE

None

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.10:
"Pressurizer Safety Valves"

PART 1:

Indian Point 3
Improved Technical Specifications and Bases

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.10 Pressurizer Safety Valves

LCO 3.4.10 Three pressurizer safety valves shall be OPERABLE with lift settings set ≥ 2460 psig and ≤ 2510 psig.

APPLICABILITY: MODES 1, 2, and 3,
MODE 4 with the average of the RCS cold leg temperatures greater than or equal to the LTOP arming temperature specified in LCO 3.4.12, Low Temperature Overpressure Protection (LTOP).

----------NOTE----------
The lift settings are not required to be within the LCO limits during MODES 3 and 4 for the purpose of setting the pressurizer safety valves under ambient (hot) conditions. This exception is allowed for 54 hours following entry into MODE 3 provided a preliminary cold setting was made prior to heatup.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One pressurizer safety valve inoperable.	A.1	Restore valve to OPERABLE status.	15 minutes
B. Required Action and associated Completion Time not met. OR Two or more pressurizer safety valves inoperable.	B.1 AND B.2	Be in MODE 3. Be in MODE 4 with average RCS cold leg temperature less than the LTOP arming temperature.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.10.1	Verify each pressurizer safety valve is OPERABLE in accordance with the Inservice Testing Program. Following testing, lift settings shall be ≥ 2460 psig and ≤ 2510 psig.	In accordance with the Inservice Testing Program

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.10 Pressurizer Safety Valves

BASES

BACKGROUND

The pressurizer safety valves provide, in conjunction with the Reactor Protection System, overpressure protection for the RCS. The pressurizer safety valves are totally enclosed spring loaded, self actuated valves with backpressure compensation. The safety valves are designed to prevent the system pressure from exceeding the system Safety Limit (SL), 2735 psig, which is 110% of the design pressure.

Because the safety valves are totally enclosed and self actuating, they are considered independent components. The relief capacity for each valve, 420,000 lb/hr, is based on postulated overpressure transient conditions resulting from a complete loss of steam flow to the turbine without a direct reactor trip or any other control. This event results in the maximum surge rate into the pressurizer, which specifies the minimum relief capacity for the safety valves. The discharge flow from the pressurizer safety valves is directed to the pressurizer relief tank. This discharge flow is indicated by an increase in temperature downstream of the pressurizer safety valves; or an increase in the pressurizer relief tank temperature or level; or actuation of acoustic monitors.

Overpressure protection is required in MODES 1, 2, 3, 4, and 5; however, in MODE 4, with the average of the RCS cold leg temperatures less than the LTOP arming temperature specified in LCO 3.4.12, and MODE 5 and MODE 6 with the reactor vessel head on, overpressure protection is provided by operating procedures and by meeting the requirements of LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System."

The upper and lower pressure limits are based on the ± 1% tolerance requirement (Ref. 1) for lifting pressures above 1000 psig. The lift setting is for the ambient conditions associated with MODES 1, 2, and 3. This requires either that the valves be set hot or that a correlation between hot and cold settings be established.

BASES

BACKGROUND (Continued)

Although the pressurizer safety valves must be set to ± 1% during the Surveillance, the pressurizer safety valves satisfy safety analysis assumptions and meet ASME Code requirements if the setpoint is determined to be ± 3% at the end of the surveillance interval. Therefore, the pressurizer safety valve setpoint is ± 3% for OPERABILITY; however, the valves must be reset to ± 1% during the Surveillance to allow for drift.

The pressurizer safety valves are part of the primary success path and mitigate the effects of postulated accidents. OPERABILITY of the safety valves ensures that the RCS pressure will be limited to 110% of design pressure. The consequences of exceeding the American Society of Mechanical Engineers (ASME) pressure limit (Ref. 1) could include damage to RCS components, increased leakage, or a requirement to perform additional stress analyses prior to resumption of reactor operation.

APPLICABLE SAFETY ANALYSES

All accident and safety analyses in the FSAR (Ref. 2) that require safety valve actuation assume operation of three pressurizer safety valves to limit increases in RCS pressure. No single failure is assumed for spring loaded safety valves designed in accordance with the ASME Boiler and Pressure Vessel Code. The overpressure protection analysis (Ref. 3) is also based on operation of three safety valves. Accidents that could result in overpressurization if not properly terminated include:

a. Uncontrolled rod withdrawal from full power;

b. Loss of reactor coolant flow;

c. Loss of external electrical load;

d. Loss of normal feedwater;

e. Loss of all AC power to station auxiliaries; and

BASES

APPLICABLE SAFETY ANALYSES (continued)

f. Locked rotor.

Detailed analyses of the above transients are contained in Reference 2. Safety valve actuation may be required in events a, b, c, e, and f (above) to limit the pressure increase. Compliance with this LCO is consistent with the design bases and accident analyses assumptions. The pressurizer safety valves satisfy safety analysis assumptions and meet ASME Code requirements if the setpoint is determined to be ± 3% at the end of the surveillance interval.

Pressurizer safety valves satisfy Criterion 3 of 10 CFR 50.36.

LCO

The three pressurizer safety valves are set to open at the RCS design pressure (2500 psia), and within the ASME specified tolerance, to avoid exceeding the maximum design pressure SL, to maintain accident analyses assumptions, and to comply with ASME requirements. The upper and lower pressure tolerance limits are based on the ± 1% tolerance requirements (Ref. 1) for lifting pressures above 1000 psig.

The pressurizer safety valve setpoint is ± 3% of the nominal 2485 psig setpoint for OPERABILITY; however, the valves must be reset to ± 1% of the nominal 2485 psig setpoint during the Surveillance to allow for drift during the SR interval.

The limit protected by this Specification is the reactor coolant pressure boundary (RCPB) SL of 110% of design pressure. Inoperability of one or more valves could result in exceeding the SL if a transient were to occur. The consequences of exceeding the ASME pressure limit could include damage to one or more RCS components, increased leakage, or additional stress analysis being required prior to resumption of reactor operation.

BASES

APPLICABILITY

In MODES 1, 2, and 3, and portions of MODE 4 above the LTOP arming temperature, OPERABILITY of three valves is required because the combined capacity is required to keep reactor coolant pressure below 110% of its design value during certain accidents. MODE 3 and portions of MODE 4 are conservatively included, although the listed accidents may not require the safety valves for protection.

The LCO is not applicable in MODE 4 when the average of the RCS cold leg temperatures are less than the OPS arming temperature specified in LCO 3.4.12 or in MODE 5 because LTOP is provided. Overpressure protection is not required in MODE 6 with reactor vessel head removed.

The Note allows entry ~~into~~ MODES 3 and 4 with the lift settings outside the LCO limits. This permits testing and examination of the safety valves at high pressure and temperature near their normal operating range, but only after the valves have had a preliminary cold setting. The cold setting gives assurance that the valves are OPERABLE near their design condition. Only one valve at a time will be removed from service for testing. The 54 hour exception is based on 18 hour outage time for each of the three valves. The 18 hour period is derived from industry experience that hot testing can be performed in this timeframe.

ACTIONS

A.1

With one pressurizer safety valve inoperable, restoration must take place within 15 minutes. The Completion Time of 15 minutes reflects the importance of maintaining the RCS overpressure protection. An inoperable safety valve coincident with an RCS overpressure event could challenge the integrity of the pressure boundary.

B.1 and B.2

If the Required Action of A.1 cannot be met within the required Completion Time or if two or more pressurizer safety valves are inoperable, the plant must be brought to a MODE in which the

BASES

ACTIONS

B.1 and B.2 (continued)

requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 with the average of the RCS cold leg temperatures less than the OPS arming temperature specified in LCO 3.4.12 within 12 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. With the average of the RCS cold leg temperatures less than the OPS arming temperature specified in LCO 3.4.12, overpressure protection is provided by LTOP. The change from MODE 1, 2, or 3 to MODE 4 reduces the RCS energy (core power and pressure), lowers the potential for large pressurizer insurges, and thereby removes the need for overpressure protection by three pressurizer safety valves.

SURVEILLANCE REQUIREMENTS

SR 3.4.10.1

SRs are specified in the Inservice Testing Program. Pressurizer safety valves are to be tested in accordance with the requirements of Section XI of the ASME Code (Ref. 4), which provides the activities and Frequencies necessary to satisfy the SRs. No additional requirements are specified.

The pressurizer safety valve setpoint is ± 3% for OPERABILITY; however, the valves are reset to ± 1% during the Surveillance to allow for drift.

BASES

REFERENCES

1. ASME, Boiler and Pressure Vessel Code, Section III.

2. FSAR, Chapter 14.

3. WCAP-7769, Rev. 1, June 1972.

4. ASME, Boiler and Pressure Vessel Code, Section XI.

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Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.10:
"Pressurizer Safety Valves"

PART 2:

CURRENT TECHNICAL SPECIFICATION PAGES

Annotated to show differences between CTS and ITS

CTS pages and associated TSCRs annotated for this ITS Specification :

CTS Page No.	Effective Amendment	Annotated Amendment	TSCR No.	TSCR Description	ITS Status of TSCR
3.1-4	170	170	No TSCRs	No TSCRs for this Page	N/A
3.1-7	121	121	No TSCRs	No TSCRs for this Page	N/A
T 4.1-3(1)	178 TSCR 97-156, 98-043	178 TSCR 97-156, 98-043	IPN 98-043	Instrument Channel Surveillance Intervals Extended to 24 Months	Incorporated
T 4.1-3(1)	178 TSCR 97-156, 98-043	178 TSCR 97-156, 98-043	IPN 97-156	SR Freq for Main Turbine Stop and Control Valves	Incorporated

Add LCO 3.4.10 Condition A and B and associated Required Actions (A.1) (A.2) (L.2)

2. Safety Valves

a. ~~At least one pressurizer code safety valve shall be operable, or an opening greater than or equal to the size of one code safety valve flange to allow for pressure relief, whenever the reactor head is on the vessel except for hydrostatically testing the RCS in accordance with Section XI of the ASME Boiler and Pressure Vessel Code.~~ (LA.1)

LCO 3.4.10 and Applicability

b. Three All pressurizer code safety valves shall be operable whenever the reactor is above the cold shutdown condition (Mode 1, 2, 3 and 4 when > LTOP) (L.1) except during reactor coolant system hydrostatic tests (M.1) and/or safety valve settings (Note to LCO 3.4.10) (M.2)

c. The pressurizer code safety valve lift setting shall be set ~~at 2485 psig with 1% allowance for error.~~ ≥ 2460 & ≤ 2510 psig (A.

SEE ITS 3.4.9

3. Pressurizer Heaters

Whenever the reactor is above the hot shutdown condition, the pressurizer shall be operable with at least 150 kw of pressurizer heaters.

a. With less than 150 kw of pressurizer heaters operable, restore the required inoperable heaters within 72 hours or be in at least hot shutdown within an additional 6 hours.

SEE ITS 3.4.11

4. Power Operated Relief Valves

Whenever the reactor coolant system is above 400°F, the power operated relief valves (PORVs) shall be operable or their associated block valves closed.

a. If the block valve is closed because of an inoperable PORV, the control power for the block valve must be removed.

b. If the above conditions cannot be satisfied within 1 hour, be in at least hot shutdown within 6 hours and in cold shutdown within the following 30 hours.

5. Power Operated Relief Block Valves

Whenever the reactor coolant system is above 400°F, the motor operated block valves shall be operable or closed.

a. If the block valve is inoperable, the control power is to be removed.

b. If the above conditions cannot be satisfied within 1 hour be in at least hot shutdown within the following 30 hours.

6. Deleted

Basis

When the boron concentration of the Reactor Coolant System is to be reduced the process must be uniform to prevent sudden reactivity changes in the reactor. Mixing of the reactor coolant will be sufficient to maintain a uniform boron concentration if at least one reactor coolant pump or one residual heat removal pump is running while the change is taking place. The residual heat removal pump will circulate the primary system volume in approximately one half hour. The pressurizer is of no concern because of the low pressurizer volume and because the pressurizer boron concentration will be higher than that of the rest of the reactor coolant. A.1

Heat transfer analyses show that reactor heat equivalent to 10% of rated power (P-7) can be removed with natural circulation only (1); hence, the requirement for one operating RCP above 350°F and two operating RCP's above 2% rated power provides a substantial safety factor. In addition, a single RCP or RHR pump (connected to the RCS) provides sufficient heat removal capability for removing decay heat.

The restriction on control bank withdrawal with less than four reactor coolant pumps operating when the reactor is subcritical and RCS T_{avg} is greater than 350°F is necessary to conform with the assumptions used in the transient analyses for the uncontrolled control rod withdrawal event from subcritical condition. The FSAR safety analysis for uncontrolled control rod assembly withdrawal from a subcritical condition assumes all four reactor coolant pumps to be operating within the temperature range of concern. Using this assumption the DNB design basis is satisfied for the combination of the two banks of the maximum combined worth withdrawn at maximum speed. Since there is no mechanism by which the control rods can be automatically withdrawn due to a control system error when T_{avg} is between 350°F and the no-load temperature, such an event can only be initiated as a result of human error during rod manipulation. Prohibiting control bank withdrawal with less than four RCPs operating provides assurance that the plant is operated within the accident analysis assumptions.

The reactor shall not be operated at power levels above 10% rated power with less than four (4) reactor coolant loops in operation until safety analyses for less than four loop operation have been submitted by the licensee and approval for less than four loop operation at power levels above 10% rated power has been granted by the Commission. (See license condition 2.C. (7))

Each of the pressurizer code safety valves is designed to relieve 420,000 lbs. per hr. of saturated steam at the valve set point.

If no residual heat were removed by the Residual Heat Removal System the amount of steam which could be generated at safety valve relief pressure would be less than half the capacity of a single valve. One valve therefore provides adequate protection for overpressurization.

The combined capacity of the three pressurizer safety valves is greater than the maximum surge rate resulting from complete loss of load (2) without a direct reactor trip or any other control.

TABLE 4.1-3 (Sheet 1 of 2)

FREQUENCIES FOR EQUIPMENT TESTS

SEE CTS MASTER MARKUP

	Check	Frequency
1. Control Rods	Rod drop times of all control rods	24M
2. Control Rods	Movement of at least 10 steps in any one direction of all control rods	Every 31 days during reactor critical operations
SR 3.4.10.1 3. Pressurizer Safety Valves	Set Point	24M* IAW Inservice Test Program LA.2
4. Main Steam Safety Valves	Set Point	24M
5. Containment Isolation System	Automatic actuation	24M
6. Refueling System Interlocks	Functioning	Each refueling, prior to movement of core components
7. Primary System Leakage	Evaluate	5 days/week
8. Diesel Generators Nos. 31, 32 & 33 Fuel Supply	Fuel Inventory	Weekly
9. Turbine Steam Stop And Control Valves	Closure	Not to exceed 6 months**
10. L.P. Steam Dump System (6 lines)	Closure	Monthly
11. Service Water System	Each pump starts and operates for 15 minutes (unless already operating)	Monthly
12. City Water Connections to Charging Pumps and Boric Acid Piping	Temporary connections available and valves operable	24M

SEE CTS MASTER MARKUP

* ~~Pressurizer Safety Valve setpoint test due no later than May 1996 may be deferred until the next refueling outage but no later than May 31, 1997.~~ TSCR 97-156 A.4

SEE CTS RELOCATED

** The turbine steam stop and control valves shall be tested at a frequency determined by the methodology presented in WCAP-11525, "Probabilistic Evaluation of Reduction in Turbine Valve Test Frequency," as updated by Westinghouse Report, WOG-TVTF-93-17, "Update of BB-95/96 Turbine Valve Failure Rates and Effect on Destructive Overspeed Probabilities." The maximum test interval for these valves shall not exceed six months. Surveillance interval extension as per Technical Specification 1.12 is not applicable to the maximum test interval.

Amendment No. 10, 14, 47, 65, 97, 99, 125, 126, 127, ~~129, 133, 144, 165,~~ TSCR 98-043 TSCR 97-156

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Technical Specification 3.4.10:
"Pressurizer Safety Valves"

PART 3:

DISCUSSION OF CHANGES

Differences between CTS and ITS

DISCUSSION OF CHANGES
ITS SECTION 3.4.10 - Pressurizer Safety Valves

ADMINISTRATIVE

A.1 In the conversion of the Indian Point Unit 3 Current Technical Specifications (CTS) to the plant specific Improved Technical Specifications (ITS) certain wording preferences or conventions are adopted which do not result in technical changes (either actual or interpretational). Additionally, editorial changes, reformatting, and revised numbering are adopted to make ITS consistent with the conventions in NUREG-1431, Standard Technical Specifications, Westinghouse Plants, Rev. 1, i.e., the improved Standard Technical Specifications.

The CTS Bases are deleted and replaced with comprehensive ITS Bases designed to support interpretation and implementation of the associated Technical Specifications. The Bases explain, clarify, and document the reasons (i.e., bases) for the associated Technical Specifications, and reflect the IP3 plant specific design, analyses, and licensing basis. In accordance with 10 CFR 50.36(a), the ITS Bases are included with the proposed ITS conversion application; however, deletion of the CTS Bases and the adoption of the ITS Bases is an administrative change with no impact on safety.

A.2 CTS Limiting Conditions for Operation (LCOs) and Surveillance Requirements (SRs) include statements of the objective and the applicability. The CTS statements of objective and applicability are deleted because these statements do not establish any requirements and do not provide any guidance for the application of CTS requirements. Therefore, deletion of these statements has no significant adverse impact on safety.

A.3 CTS 3.1.A.2.c specifies that pressurizer code safety valve lift setting shall be set at 2485 psig with ± 1% allowance for error. ITS LCO 3.4.10 and ITS SR 3.4.10.1 maintain the Limiting Condition for Operation as pressurizer code safety valves must be set to ± 1% of the nominal 2485 psig setpoint (i.e., ≥ 2460 psig and ≤ 2510 psig); however, ITS 3.4.10 Bases include the clarification that pressurizer safety valve setpoint limit (i.e., Operability requirement) is ± 3% of the nominal 2485 psig

setpoint. The LCO is that the valves must be reset to ± 1% of the nominal 2485 psig setpoint during the Surveillance to allow for drift during the SR interval. This is needed and is acceptable because the pressurizer safety valves satisfy safety analysis assumptions and meet ASME Code requirements if the setpoint is determined to be ± 3% at the end of the surveillance interval. Therefore, the pressurizer safety valve setpoint is ± 3% for OPERABILITY; however, the valves must be reset to ± 1% during the Surveillance to allow for drift during the SR interval.

This is an administrative change with no impact on safety because this practice (i.e., pressurizer safety valve setpoint is ± 3% for Operability but must be reset to ± 1% during the SR to allow for drift) is consistent with the overpressure analysis, current IP3 practice and the requirements of the ASME, Boiler and Pressure Vessel Code, Section XI.

A.4 CTS Table 4.1-3, Note to Pressurizer Safety Valve Frequency, specifies that the safety valve setpoint test due May 1996 may be deferred until the next refueling outage but no later than May 31, 1997. This note is deleted because the allowance provided has expired. This is an administrative change with no impact on safety.

MORE RESTRICTIVE

M.1 CTS 3.1.A.2.b specifies that pressurizer code safety valves must be Operable above the cold shutdown condition except during reactor coolant system hydrostatic tests. ITS LCO 3.4.10 maintains the requirement that pressurizer code safety valves must be Operable during normal plant operation (See ITS LCO 3.4.10, DOC L.1) but exception during reactor coolant system hydrostatic tests is deleted. This change is acceptable because current Section XI of the ASME Boiler and Pressure Vessel Code requirements for an inservice leak and hydrostatic (ISLH) testing allow the testing to be performed at pressures and temperatures where pressurizer code safety valves can and should be available to provide overpressure protection for the reactor coolant system. This change is acceptable because it does not introduce any operation which is

un-analyzed while ensuring that pressurizer code safety valves will be available during ISLH testing. Therefore, this change has no adverse impact on safety.

M.2 CTS 3.1.A.2.b specifies that pressurizer code safety valves must be Operable above the cold shutdown condition except during safety valve settings. ITS LCO 3.4.10 maintains the requirement that pressurizer code safety valves must be Operable during normal plant operation (See ITS LCO 3.4.10, DOC L.1) but the exception for safety valve settings includes additional clarifications and restrictions. Specifically, ITS LCO 3.4.10, Note to Applicability, specifies that the exception to the LCO for pressurizer code safety valves is valid during valve adjustment in Modes 3 and 4 and for a period no longer than 54 hours (18 hours to adjust each of the three valves) and only if a preliminary cold setting was done before the heatup.

This more restrictive change is needed to ensure that appropriate restrictions (prohibiting critical operation and requiring a cold lift setting adjustment) are established when the performance of a surveillance requires entry into the applicable conditions of the LCO in order to complete the test. Additionally, this change ensures that limits are established for the maximum time that pressurizer safety valves may not be operable due to lift setpoints not being set at normal operating temperature. This more restrictive change is acceptable because it does not introduce any operation that is un-analyzed while placing additional restrictions on the conditions and the time that pressurizer safety valves may not be operable when lift setpoints are being adjusted. Therefore, this change has no adverse impact on safety.

LESS RESTRICTIVE

L.1 CTS 3.1.A.2.b specifies that pressurizer code safety valves must be Operable above the cold shutdown condition (i.e., Modes 1, 2, 3 and 4).

ITS LCO 3.4.10 specifies that pressurizer code safety valves must be Operable in Modes 1, 2, and 3, and in Mode 4 but when above the Low Temperature Overpressure Protection (LTOP) arming temperature.

Therefore, ITS LCO 3.4.10 eliminates the requirement for pressurizer code safety valve OPERABILITY when ITS LCO 3.4.12, Low Temperature Overpressure Protection (LTOP), governs overpressure protection requirements for the reactor coolant system.

This change is acceptable because RCS overpressure protection required by ITS LCO 3.4.12, Low Temperature Overpressure Protection, will ensure adequate protection of the RCS pressure boundary without the use of pressurizer safety valves whenever the RCS is below the LTOP arming temperature. This change has no impact on safety because ITS LCO 3.4.10 and 3.4.12 ensure that RCS overpressure protection consistent with safety analysis assumptions is provided at all times.

L.2 CTS 3.1.A.2 establishes requirements for the OPERABILITY of pressurizer code safety valves but does not specify any required action if this LCO is not met.

ITS LCO 3.4.10, Conditions A and B, establishes required actions when one or more pressurizer safety valves are not operable. Specifically, Condition A requires that with one pressurizer safety valve inoperable, restoration must take place within 15 minutes. This change is needed because an inoperable safety valve coincident with an RCS overpressure event could challenge the integrity of the pressure boundary. Condition B requires that if two or more pressurizer safety valves are inoperable or if the requirements of Required Action A.1 cannot be met, then the plant must be brought to a Mode in which the requirement does not apply (i.e., below the LTOP protection arming temperature). This change is needed because if there is less than the required overpressure protection (setpoint or capacity), then the RCS can be protected only by reducing the RCS energy (core power and pressure) which lowers the potential for large pressurizer insurges, and thereby removes the need for overpressure protection. Additionally, at the lower pressure, LCO 3.4.12, Low Temperature Overpressure Protection, will ensure adequate protection of the RCS pressure boundary. Therefore, this change has no adverse impact on safety.

REMOVED DETAIL

LA.1 CTS 3.1.A.2 requires that at least one pressurizer code safety valve shall be Operable or an opening greater than or equal to the size of one code safety valve flange shall be maintained whenever the reactor head is on the vessel (See ITS LCO 3.4.10, DOC M.1 for hydrostatic test exception).

ITS LCO 3.4.10 maintains this requirement in Modes 1, 2, and 3, and in Mode 4 but when above the Low Temperature Overpressure Protection (LTOP) arming temperature; however, ITS LCO 3.4.10 does not include any requirements for pressurizer code safety valves below the LTOP arming temperature. When below the LTOP arming temperature, requirements needed to satisfy ASME Code for at least one pressurizer code safety valve or an opening greater than or equal to the size of one code safety valve flange will be maintained in the FSAR.

This change is needed because ITS LCO 3.4.12, LTOP, ensures overpressure relief setpoints or alternate LTOP requirements prevent violation of brittle fracture limits when below the LTOP arming temperature whereas pressurizer relief setpoints may be higher than brittle fracture limits at lower temperatures.

This change is acceptable because ITS LCO 3.4.10 maintains the requirement for pressurizer code safety valves in Modes 1, 2, and 3, and in Mode 4 when above the LTOP arming temperature and ITS LCO 3.4.12 establishes more restrictive requirements for reactor coolant system overpressure protection without the use of any pressurizer safety valves when below the LTOP arming temperature. Additionally, the FSAR will maintain requirements for at least one pressurizer code safety valve to be Operable or an opening greater than or equal to the size of one code safety valve flange below the LTOP arming temperature.

This change is acceptable because there is no change to the existing requirements by the relocation of requirements to the TRM and future changes to the TRM will be controlled in accordance with 10 CFR 50.59. This change is a less restrictive administrative change with no impact on safety because ITS 3.4.10 and ITS 3.4.12 maintain the requirements for RCS overpressure protection. Therefore, requirements for

pressurizer code safety valves when below the LTOP arming temperature can be maintained in the FSAR with no significant adverse impact on safety.

LA.2 CTS Table 4.1-3, Item 3, Pressurizer Safety Valves, requires verification of the setpoints every 24 months.

ITS SR 3.4.10.1 maintains the requirement to verify the Operability of pressurizer safety valves including setpoint verification; however, the Frequency is specified as in accordance with the Inservice Test (IST) Program. The IST program requires that pressurizer safety valves are tested every 24 months.

This change is needed and is acceptable because the IST program is required by ITS 5.5.7 and provides controls for inservice testing of all ASME Code Class 1, 2, and 3 components. Specifically, ITS 5.5.7, Inservice Testing Program (IST), requires establishing and maintaining a program for inservice testing of ASME Code Class 1, 2, and 3 components at frequencies specified in Section XI of the ASME Boiler and Pressure Vessel Code. Additionally, 10 CFR 50.55a(f) already provides the regulatory requirements for this IST Program, and specifies that ASME Code Class 1, 2, and 3 pumps and valves are covered by an IST Program.

ITS LCO 3.4.10 will still require that pressurizer safety valves must be operable and set within specific limits and ITS SR 3.4.10.1 will still require periodic verification of Operability. These requirements, in conjunction with the IST Program required by ITS 5.5.7, provide a high degree of assurance that safety valves will be tested and maintained to ensure pressurizer safety valve Operability. Additionally, ITS 5.5.7, Inservice Testing Program (IST), requirements and 10 CFR 50.55a(f) ensure adequate change control and regulatory oversight for any changes to the existing requirements. Therefore, requirements to test pressurizer safety valves can be maintained in the IST program with no significant adverse impact on safety.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.10:
"Pressurizer Safety Valves"

PART 4:

No Significant Hazards Considerations for Changes between CTS and ITS that are Less Restrictive

No Significant Hazard Considerations for Changes that are Administrative, More Restrictive, and Removed Details are the same for all Packages. A Copy is included at the end of the Package.

NO SIGNIFICANT HAZARDS EVALUATION
ITS SECTION 3.4.10 - Pressurizer Safety Valves

LESS RESTRICTIVE
("L.1" Labeled Comments/Discussions)

New York Power Authority has evaluated the proposed Technical Specification change identified as "Less Restrictive" in accordance with the criteria set forth in 10 CFR 50.92, and has determined that the proposed change does not involve a significant hazards consideration. The bases for the determination that the proposed changes do not involve a significant hazards consideration are discussed below.

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

   This change modifies the applicability for pressurizer safety valves to eliminate requirements for pressurizer safety valves when LTOP requirements are applicable. This change will not result in a significant increase in the probability of an accident previously evaluated because using LTOP requirements versus pressurizer safety valves for overpressure protection at lower temperatures is not related to the precursor of any analyzed accident. This change will not result in a significant increase in the consequences of an accident previously evaluated because ITS LCO 3.4.12, LTOP, ensures overpressure relief setpoints or alternate LTOP requirements prevent violation of brittle fracture limits when below the LTOP arming temperature.

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

   The proposed changes will not involve any physical changes to plant systems, structures, or components (SSC). The changes in normal Plant operation are consistent with the current safety analysis assumptions because ITS LCO 3.4.12, LTOP, already ensures overpressure relief setpoints or alternate LTOP requirements prevent violation of brittle fracture limits when below the LTOP arming temperature. Therefore, these changes will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

This change does not involve a significant reduction in a margin of safety because ITS LCO 3.4.12, LTOP, already ensures overpressure relief setpoints or alternate LTOP requirements prevent violation of brittle fracture limits when below the LTOP arming temperature whereas pressurizer relief setpoints may be higher than brittle fracture limits at lower temperatures.

LESS RESTRICTIVE
("L.2" Labeled Comments/Discussions)

New York Power Authority has evaluated the proposed Technical Specification change identified as "Less Restrictive" in accordance with the criteria set forth in 10 CFR 50.92, and has determined that the proposed change does not involve a significant hazards consideration. The bases for the determination that the proposed changes do not involve a significant hazards consideration are discussed below.

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

This change establishes new requirements to initiate a normal plant shutdown immediately if 2 pressurizer code safety valves are inoperable and within 15 minutes if 1 pressurizer code safety valve is inoperable. Under the same conditions, CTS requires an immediate shutdown because no Actions are specified.

This change will not result in a significant increase in the probability of an accident previously evaluated because the Operability status of pressurizer code safety valves is not related to the precursor of any analyzed accident. This change will not result in a significant increase in the consequences of an accident previously evaluated because the proposed Actions ensure the plant is promptly shutdown in an orderly manner and without challenging plant systems when minimum requirements for pressurizer code safety valves are not met.

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

   The proposed changes will not involve any physical changes to plant systems, structures, or components (SSC). The changes in normal Plant operation are consistent with the current safety analysis assumptions. Therefore, these changes will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   This change does not involve a significant reduction in a margin of safety because the proposed Actions ensure the plant is promptly shutdown in an orderly manner and without challenging plant systems when minimum requirements for pressurizer code safety valves are not met.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.10:
"Pressurizer Safety Valves"

PART 5:

NUREG-1431
Annotated to show differences between
NUREG-1431 and ITS

Status of NUREG 1431 Generic Changes for ITS 3.4.10

This ITS Specification is based on NUREG-1431 Specification No. **3.4.10**
as modified by the following Generic Changes:

OG No.	TSTF No.	Generic Change Description	NRC STATUS	IP3 STATUS	JD No.
WOG-067 R1		RELOCATE LTOP ARMING TEMPERATURE TO PTLR	Rejected by TSTF	Not Incorporated	N/A

3.4 REACTOR COOLANT SYSTEM (RCS)

<CTS>

3.4.10 Pressurizer Safety Valves

<3.1.A.2.b>
<3.1.A.2.c>

LCO 3.4.10 ~~[~~Three~~]~~ pressurizer safety valves shall be OPERABLE with lift settings set ≥ ~~[~~2460~~]~~ psig and ≤ ~~[~~2510~~]~~ psig. PA.1

<3.1.A.2.b>
<DOC L.1>
<DOC M.1>

APPLICABILITY: MODES 1, 2, and 3,
MODE 4 with ~~a1~~ the average of the RCS cold leg temperatures ~~≥ [275]°F~~. DB.3 DB2

Insert: 3.4-21-01

---NOTE---

The lift settings are not required to be within the LCO limits during MODES 3 and 4 for the purpose of setting the pressurizer safety valves under ambient (hot) conditions. This exception is allowed for ~~[~~54~~]~~ hours following entry into MODE 3 provided a preliminary cold setting was made prior to heatup.

<3.1.A.2.b>
<DOC M.2>

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One pressurizer safety valve inoperable.	A.1 Restore valve to OPERABLE status.	15 minutes
B. Required Action and associated Completion Time not met. OR Two or more pressurizer safety valves inoperable.	B.1 Be in MODE 3. AND B.2 Be in MODE 4 with ~~any~~ the average of the RCS cold leg temperatures ~~≤ [275]°F~~.	6 hours 12 hours

<DOC L.2>

<DOC L.2>

DB.2

Insert: 3.4-21-02

DB.3

INSERT: 3.4-21-01

greater than or equal to the LTOP arming temperature specified in LCO 3.4.12, Low Temperature Overpressure Protection (LTOP).

INSERT: 3.4-21-02

less than the LTOP arming temperature.

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.10.1	Verify each pressurizer safety valve is OPERABLE in accordance with the Inservice Testing Program. Following testing, lift settings shall be ~~within ± 1%~~. ≥ 2460 psig and ≤ 2510 psig	In accordance with the Inservice Testing Program

PA.1

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.10 Pressurizer Safety Valves

BASES

BACKGROUND

The pressurizer safety valves provide, in conjunction with the Reactor Protection System, overpressure protection for the RCS. The pressurizer safety valves are totally enclosed ~~pop type~~, spring loaded, self actuated valves with backpressure compensation. The safety valves are designed to prevent the system pressure from exceeding the system Safety Limit (SL), ~~[2735]~~ psig, which is 110% of the design pressure.

Because the safety valves are totally enclosed and self actuating, they are considered independent components. The relief capacity for each valve, ~~380,000~~ 420,000 lb/hr, is based on postulated overpressure transient conditions resulting from a complete loss of steam flow to the turbine without a direct reactor trip or any other control. This event results in the maximum surge rate into the pressurizer, which specifies the minimum relief capacity for the safety valves. The discharge flow from the pressurizer safety valves is directed to the pressurizer relief tank. This discharge flow is indicated by an increase in temperature downstream of the pressurizer safety valves ; or, or increase in the pressurizer relief tank temperature or level; or, actuation of acoustic monitors. DB.1

Overpressure protection is required in MODES 1, 2, 3, 4, and 5; however, in MODE 4, with ~~one or more~~ the average of the RCS cold leg temperatures ~~≤ [275] °F~~ and MODE 5 and MODE 6 with the reactor vessel head on, overpressure protection is provided by operating procedures and by meeting the requirements of LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System." DB.2

Insert B 3.4-45-01

The upper and lower pressure limits are based on the ± 1% tolerance requirement (Ref. 1) for lifting pressures above 1000 psig. The lift setting is for the ambient conditions associated with MODES 1, 2, and 3. This requires either that the valves be set hot or that a correlation between hot and cold settings be established.

Insert: B3.4-45-02

The pressurizer safety valves are part of the primary success path and mitigate the effects of postulated accidents. OPERABILITY of the safety valves ensures that the RCS pressure will be limited to 110% of design pressure.

(continued)

INSERT: B 3.4-45-01

less than the LTOP enable temperature specified in LCO 3.4.12

INSERT: B 3.4-45-02

Although the pressurizer safety valves must be set to ± 1% during the Surveillance, the pressurizer safety valves satisfy safety analysis assumptions and meet ASME Code requirements if the setpoint is determined to be ± 3% at the end of the surveillance interval. Therefore, the pressurizer safety valve setpoint is ± 3% for OPERABILITY; however, the valves must be reset to ± 1% during the Surveillance to allow for drift.

BASES

BACKGROUND (continued)

The consequences of exceeding the American Society of Mechanical Engineers (ASME) pressure limit (Ref. 1) could include damage to RCS components, increased leakage, or a requirement to perform additional stress analyses prior to resumption of reactor operation.

APPLICABLE SAFETY ANALYSES

Insert: B3.4-46-03

All accident and safety analyses in the FSAR (Ref. 2) that require safety valve actuation assume operation of three pressurizer safety valves to limit increases in RCS pressure. The overpressure protection analysis (Ref. 3) is also based on operation of [three] safety valves. Accidents that could result in overpressurization if not properly terminated include:

a. Uncontrolled rod withdrawal from full power;

b. Loss of reactor coolant flow;

c. Loss of external electrical load;

d. Loss of normal feedwater;

e. Loss of all AC power to station auxiliaries; and

f. Locked rotor.

Detailed analyses of the above transients are contained in Reference 2. Safety valve actuation is required in events c, d, and e (above) to limit the pressure increase. Compliance with this LCO is consistent with the design bases and accident analyses assumptions.

may be

DB.1

a, b, c, e and f

Insert: B3.4-46-01

Pressurizer safety valves satisfy Criterion 3 of the NRC Policy Statement.

10 CFR 50.36

LCO

The [three] pressurizer safety valves are set to open at the RCS design pressure (2500 psia), and within the ASME specified tolerance, to avoid exceeding the maximum design pressure SL, to maintain accident analyses assumptions, and to comply with ASME requirements. The upper and lower pressure tolerance limits are based on the ± 1% tolerance requirements (Ref. 1) for lifting pressures above 1000 psig.

Insert: B3.4-46-02

PA.1

(continued)

INSERT: B 3.4-46-01

The pressurizer safety valves satisfy safety analysis assumptions and meet ASME Code requirements if the setpoint is determined to be ± 3% at the end of the surveillance interval.

INSERT: B 3.4-46-02

The pressurizer safety valve setpoint is ± 3% of the nominal 2485 psig setpoint for OPERABILITY; however, the valves must be reset to ± 1% of the nominal 2485 psig setpoint during the Surveillance to allow for drift during the SR interval.

INSERT: B 3.4-46-03

No single failure is assume for spring loaded safety valves designed in accordance with ASME Boi8ler and Pressure Vessel Code.

BASES

LCO (continued)

The limit protected by this Specification is the reactor coolant pressure boundary (RCPB) SL of 110% of design pressure. Inoperability of one or more valves could result in exceeding the SL if a transient were to occur. The consequences of exceeding the ASME pressure limit could include damage to one or more RCS components, increased leakage, or additional stress analysis being required prior to resumption of reactor operation.

APPLICABILITY

In MODES 1, 2, and 3, and portions of MODE 4 above the LTOP arming temperature, OPERABILITY of [three] valves is required because the combined capacity is required to keep reactor coolant pressure below 110% of its design value during certain accidents. MODE 3 and portions of MODE 4 are conservatively included, although the listed accidents may not require the safety valves for protection.

the average of the

The LCO is not applicable in MODE 4 when all RCS cold leg temperatures are ≤ [275] °F or in MODE 5 because LTOP is provided. Overpressure protection is not required in MODE 6 with reactor vessel head detensioned.

Insert B3.4-47-01

removed

The Note allows entry into MODES 3 and 4 with the lift settings outside the LCO limits. This permits testing and examination of the safety valves at high pressure and temperature near their normal operating range, but only after the valves have had a preliminary cold setting. The cold setting gives assurance that the valves are OPERABLE near their design condition. Only one valve at a time will be removed from service for testing. The [54] hour exception is based on 18 hour outage time for each of the [three] valves. The 18 hour period is derived from operating experience that hot testing can be performed in this timeframe.

industry

ACTIONS

A.1

With one pressurizer safety valve inoperable, restoration must take place within 15 minutes. The Completion Time of 15 minutes reflects the importance of maintaining the RCS Overpressure Protection ~~System~~. An inoperable safety valve

(continued)

INSERT: B 3.4-47-01

less than the LTOP arming temperature specified in LCO 3.4.12

BASES

ACTIONS

A.1 (continued)

coincident with an RCS overpressure event could challenge the integrity of the pressure boundary.

the average of the

DB 3

B.1 and B.2

If the Required Action of A.1 cannot be met within the required Completion Time or if two or more pressurizer safety valves are inoperable, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 with ~~any~~ RCS cold leg temperatures ≤ [275]°F within 12 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. With ~~any~~ RCS cold leg temperatures ~~at or below [275]°F~~, overpressure protection is provided by ~~the~~ LTOP ~~System~~. The change from MODE 1, 2, or 3 to MODE 4 reduces the RCS energy (core power and pressure), lowers the potential for large pressurizer insurges, and thereby removes the need for overpressure protection by ~~[~~three~~]~~ pressurizer safety valves.

Insert B3.4-48-01

SURVEILLANCE REQUIREMENTS

SR 3.4.10.1

SRs are specified in the Inservice Testing Program. Pressurizer safety valves are to be tested in accordance with the requirements of Section XI of the ASME Code (Ref. 4), which provides the activities and Frequencies necessary to satisfy the SRs. No additional requirements are specified.

The pressurizer safety valve setpoint is ± ~~[~~3~~]~~% for OPERABILITY; however, the valves are reset to ± 1% during the Surveillance to allow for drift.

REFERENCES

1. ASME, Boiler and Pressure Vessel Code, Section III.
2. FSAR, Chapter ~~[15]~~. 14

(continued)

INSERT: B 3.4-48-01

less than the LTOP enable temperature specified in LCO 3.4.12

BASES

REFERENCES (continued)

3. WCAP-7769, Rev. 1, June 1972.

4. ASME, Boiler and Pressure Vessel Code, Section XI.

Indian Point 3
Improved Technical Specifications (ITS)
Conversion Package

Technical Specification 3.4.10:
"Pressurizer Safety Valves"

PART 6:

Justification of Differences between

NUREG-1431 and IP3 ITS

JUSTIFICATION OF DIFFERENCES FROM NUREG-1431
ITS SECTION 3.4.10 - Pressurizer Safety Valves

RETENTION OF EXISTING REQUIREMENT (CURRENT LICENSING BASIS)

None

PLANT-SPECIFIC WORDING PREFERENCE OR MINOR EDITORIAL IMPROVEMENT

PA.1 Corrected typographical error or made a minor editorial improvement to improve clarity and ensure requirements are fully understood and consistently applied. There are no technical changes to requirements as specified in NUREG 1431, Rev. 1; therefore, this change is not a significant or generic deviation from NUREG 1431, Rev 1.

PLANT-SPECIFIC DIFFERENCE IN THE DESIGN OR DESIGN BASIS

DB.1 Design or implementation details are incorporated or revised as necessary to more precisely describe IP3 current design or practice. These changes are intended to describe the design, improve clarity, or ensure requirements are fully understood and consistently applied. Unless identified and described blow, these changes are self-explanatory. A detailed description of the design, accident analysis assumptions, and Operability requirements are incorporated into the IP3 ITS Bases. These changes maintain the IP3 current licensing basis except as identified and justified in the CTS/ITS discussion of changes.

DB.2 NUREG 1431, Rev 1, LCO 3.4.10, specifies that requirements for pressurizer safety valves are applicable when all RCS cold leg temperatures are ≥ 275°F. IP3 ITS LCO 3.4.10, specifies that requirements for pressurizer safety valves are applicable when all RCS cold leg temperatures are greater than or equal to the LTOP enable temperature specified in LCO 3.4.12, Low Temperature Overpressure Protection (LTOP).

DIFFERENCE BASED ON A GENERIC CHANGE TRAVELER FOR NUREG-1431

None

DIFFERENCE FOR ANY REASON OTHER THAN ABOVE

None