UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

PHILADELPHIA ELECTRIC COMPANY

DOCKET NO. 50-352

LIMERICK GENERATING STATION, UNIT 1

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 28
License No. NPF-39

1. The Nuclear Regulatory Commission (the Commission) has found that

   A. The application for amendment by Philadelphia Electric Company (the licensee) dated April 10, 1989, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 2.C.(2) of Facility Operating License No. NPF-39 is hereby amended to read as follows:

   Technical Specifications

   The Technical Specifications contained in Appendix A and the Environmental Protection Plan contained in Appendix B, as revised through Amendment No. 28 , are hereby incorporated into this license. Philadelphia Electric Company shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. This license amendment is effective as of its date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

/s/
Walter R. Butler, Director
Project Directorate I-2
Division of Reactor Projects I/II

Attachment:
Changes to the Technical
Specifications

Date of Issuance: June 20, 1989

PDI-2/LA	PDI-2/PM	OGC	PDI-2/D
MO'Brien	RClark:mj		WButler
6/20/89	05/31/89 06/02/89	6/8/89	6/20/89

3. This license amendment is effective as of its date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

Walter R. Butler

Walter R. Butler, Director
Project Directorate I-2
Division of Reactor Projects I/II

Attachment:
Changes to the Technical
Specifications

Date of Issuance: June 20, 1989

ATTACHMENT TO LICENSE AMENDMENT NO. 28

FACILITY OPERATING LICENSE NO. NPF-39

DOCKET NO. 50-352

Replace the following pages of the Appendix A Technical Specifications with the attached page. The revised pages are identified by Amendment number and contain vertical lines indicating the area of change. Overleaf pages are provided to maintain document completeness.*

Remove	Insert
3/4 3-1	3/4 3-1*
3/4 3-2	3/4 3-2
3/4 3-11	3/4 3-11
3/4 3-12	3/4 3-12*
3/4 3-17	3/4 3-17
3/4 3-18	3/4 3-18
3/4 3-23	3/4 3-23
3/4 3-24	3/4 3-24*
3/4 3-27	3/4 3-27
3/4 3-28	3/4 3-28*
3/4 4-9	3/4 4-9
3/4 4-10	3/4 4-10*
3/4 6-57	3/4 6-57
3/4 6-58	3/4 6-58*
3/4 7-13	3/4 7-13
3/4 7-14	3/4 7-14*
6-5	6-5
6-6	6-6*

3/4.3 INSTRUMENTATION

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.1 As a minimum, the reactor protection system instrumentation channels shown in Table 3.3.1-1 shall be OPERABLE with the REACTOR PROTECTION SYSTEM RESPONSE TIME as shown in Table 3.3.1-2.

APPLICABILITY: As shown in Table 3.3.1-1.

ACTION:

a. With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement for one trip system, place the inoperable channel(s) and/or that trip system in the tripped condition* within 1 hour. The provisions of Specification 3.0.4 are not applicable.

b. With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement for both trip systems, place at least one trip system** in the tripped condition within 1 hour and take the ACTION required by Table 3.3.1-1.

SURVEILLANCE REQUIREMENTS

4.3.1.1 Each reactor protection system instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations for the OPERATIONAL CONDITIONS and at the frequencies shown in Table 4.3.1.1-1.

4.3.1.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed at least once per 18 months.

4.3.1.3 The REACTOR PROTECTION SYSTEM RESPONSE TIME of each reactor trip functional unit shown in Table 3.3.1-2 shall be demonstrated to be within its limit at least once per 18 months. Each test shall include at least one channel per trip system such that all channels are tested at least once every N times 18 months where N is the total number of redundant channels in a specific reactor trip system.

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*An inoperable channel need not be placed in the tripped condition where this would cause the Trip Function to occur. In these cases, the inoperable channel shall be restored to OPERABLE status within 2 hours or the ACTION required by Table 3.3.1-1 for that Trip Function shall be taken.

**The trip system need not be placed in the tripped condition if this would cause the Trip Function to occur. When a trip system can be placed in the tripped condition without causing the Trip Function to occur, place the trip system with the most inoperable channels in the tripped condition; if both systems have the same number of inoperable channels, place either trip system in the tripped condition.

TABLE 3.3.1-1

REACTOR PROTECTION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	APPLICABLE OPERATIONAL CONDITIONS	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (a)	ACTION
1. Intermediate Range Monitors(b):			
a. Neutron Flux - High	2	3	1
	3, 4	3	2
	5(c)	3(d)	3
b. Inoperative	2	3	1
	3, 4	3	2
	5	3(d)	3
2. Average Power Range Monitor(e):			
a. Neutron Flux - Upscale, Setdown	2	2	1
	3	2	2
	5(c)	2(d)	3
b. Neutron Flux - Upscale			
1) Flow Biased	1	2	4
2) High Flow Clamped	1	2	4
c. Inoperative	1, _	2	1
	3	2	2
	5(c)	2(d)	3
d. Downscale	1(g)	2	4
3. Reactor Vessel Steam Dome Pressure - High	1, 2(f)	2	1
4. Reactor Vessel Water Level - Low, Level 3	1, 2	2	1
5. Main Steam Line Isolation Valve - Closure	1(g)	1/valve	4

TABLE 3.3.2-1
ISOLATION ACTUATION INSTRUMENTATION

TRIP FUNCTION	ISOLATION SIGNAL (a)	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (b)	APPLICABLE OPERATIONAL CONDITION	ACTION
1. MAIN STEAM LINE ISOLATION				
a. Reactor Vessel Water Level				
1) Low, Low-Level 2	B	2	1, 2, 3	21
2) Low, Low, Low-Level 1	C	2	1, 2, 3	21
b. Main Steam Line Radiation - High	D	2	1, 2, 3	21
c. Main Steam Line Pressure - Low	P	2	1	22
d. Main Steam Line Flow - High	E	2/line	1, 2, 3	20
e. Condenser Vacuum - Low	Q	2	1, 2**, 3**	21
f. Outboard MSIV Room Temperature - High	$F^{(f)}$	2	1, 2, 3	21
g. Turbine Enclosure - Main Steam Line Tunnel Temperature - High	$F^{(f)}$	14	1, 2, 3	21
h. Manual Initiation	NA	2	1, 2, 3	24
2. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION				
a. Reactor Vessel Water Level Low - Level 3	A	2	1, 2, 3	23
b. Reactor Vessel (RHR Cut-In Permissive) Pressure - High	V	2	1, 2, 3	23
c. Manual Initiation	NA	1	1, 2, 3	24

TABLE 3.3.2-1 (Continued)
ISOLATION ACTUATION INSTRUMENTATION

TRIP FUNCTION	ISOLATION SIGNAL (a)	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (b)	APPLICABLE OPERATIONAL CONDITION	ACTION
3. REACTOR WATER CLEANUP SYSTEM ISOLATION				
a. RWCS Δ Flow - High	J	1	1, 2, 3	23
b. RWCS Area Temperature - High	J	6	1, 2, 3	23
c. RWCS Area Ventilation Δ Temperature - High	J	6	1, 2, 3	23
d. SLCS Initiation	$Y^{(d)}$	NA	1, 2, 3	23
e. Reactor Vessel Water Level - Low, Low - Level 2	B	2	1, 2, 3	23
f. Manual Initiation	NA	1	1, 2, 3	24
4. HIGH PRESSURE COOLANT INJECTION SYSTEM ISOLATION				
a. HPCI Steam Line Δ Pressure - High	L	1	1, 2, 3	23
b. HPCI Steam Supply Pressure - Low	LA	2	1, 2, 3	23
c. HPCI Turbine Exhaust Diaphragm Pressure - High	L	2	1, 2, 3	23
d. HPCI Equipment Room Temperature - High	L	1	1, 2, 3	23
e. HPCI Equipment Room Δ Temperature - High	L	1	1, 2, 3	23

TABLE 3.3.2-1 (Continued)

TABLE NOTATIONS

(e) Manual initiation isolates the steam supply line outboard isolation valve and only following manual or automatic initiation of the system.

(f) In the event of a loss of ventilation the temperature - high setpoint may be raised by 50°F for a period not to exceed 30 minutes to permit restoration of the ventilation flow without a spurious trip. During the 30 minute period, an operator, or other qualified member of the technical staff, shall observe the temperature indications continuously, so that, in the event of rapid increases in temperature, the main steam lines shall be manually isolated.

(g) Wide range accident monitor per Specification 3.3.7.5.

TABLE 3.3.2-2

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. MAIN STEAM LINE ISOLATION		
a. Reactor Vessel Water Level		
1) Low, Low - Level 2	≥ - 38 inches*	≥ - 45 inches
2) Low, Low, Low - Level 1	≥ - 129 inches*	≥ - 136 inches
b. Main Steam Line Radiation - High	≤ 3.0 x Full Power Background	≤ 3.6 x Full Power Background
c. Main Steam Line Pressure - Low	≥ 756 psig	≥ 736 psig
d. Main Steam Line Flow - High	≤ 108.7 psid	≤ 111.7 psid
e. Condenser Vacuum - Low	10.5 psia	≥ 10.1 psia/≤ 10.9 psia
f. Outboard MSIV Room Temperature - High	≤ 192°F	≤ 200°F
g. Turbine Enclosure - Main Steam Line Tunnel Temperature - High	≤ 165°F	≤ 175°F
h. Manual Initiation	N.A.	N.A.
2. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION		
a. Reactor Vessel Water Level Low - Level 3	≥ 12.5 inches*	≥ 11.0 inches
b. Reactor Vessel (RHR Cut-in Permissive) Pressure - High	≤ 75 psig	≤ 95 psig
c. Manual Initiation	N.A.	N.A.

TABLE 3.3.2-3

ISOLATION SYSTEM INSTRUMENTATION RESPONSE TIME

TRIP FUNCTION	RESPONSE TIME (Seconds)#
1. MAIN STEAM LINE ISOLATION	
a. Reactor Vessel Water Level	
1) Low, Low - Level 2	$\leq 13^{(a)}$**
2) Low, Low, Low - Level 1	≤ 1.0*
b. Main Steam Line Radiation - High(b)	≤ 1.0*/$\leq 13^{(a)}$**
c. Main Steam Line Pressure - Low	≤ 1.0*/$\leq 13^{(a)}$**
d. Main Steam Line Flow - High	≤ 0.5*/$\leq 13^{(a)}$**
e. Condenser Vacuum - Low	N.A.
f. Outboard MSIV Room Temperature - High	N.A.
g. Turbine Enclosure - Main Steam Line Tunnel Temperature - High	N.A.
h. Manual Initiation	N.A.
2. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION	
a. Reactor Vessel Water Level Low - Level 3	$\leq 13^{(a)}$
b. Reactor Vessel (RHR Cut-In Permissive) Pressure - High	N.A.
c. Manual Initiation	N.A.
3. REACTOR WATER CLEANUP SYSTEM ISOLATION	
a. RWCS Δ Flow - High	≤ 13##
b. RWCS Area Temperature - High	N.A.
c. RWCS Area Ventilation Δ Temperature - High	N.A.
d. SLCS Initiation	N.A.
e. Reactor Vessel Water Level - Low, Low - Level 2	$\leq 13^{(a)}$
f. Manual Initiation	N.A.

TABLE 3.3.2-3 (Continued)

ISOLATION SYSTEM INSTRUMENTATION RESPONSE TIME

TRIP FUNCTION	RESPONSE TIME (Seconds)#
4. HIGH PRESSURE COOLANT INJECTION SYSTEM ISOLATION	
a. HPCI Steam Line Δ Pressure - High	≤ 13(a)
b. HPCI Steam Supply Pressure - Low	≤ 13(a)
c. HPCI Turbine Exhaust Diaphragm Pressure - High	N.A.
d. HPCI Equipment Room Temperature - High	N.A.
e. HPCI Equipment Room Δ Temperature - High	N.A.
f. HPCI Pipe Routing Area Temperature - High	N.A.
g. Manual Initiation	N.A.
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION	
a. Reactor Steam Line Δ Pressure - High	≤ 13(a)
b. RCIC Steam Supply Pressure - Low	≤ 13(a)
c. RCIC Turbine Exhaust Diaphragm Pressure - High	N.A.
d. RCIC Equipment Room Temperature - High	N.A.
e. RCIC Equipment Room Δ Temperature - High	N.A.
f. RCIC Pipe Routing Area Temperature - High	N.A.
g. Manual Initiation	N.A.

TABLE 4.3.2.1-1

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. MAIN STEAM LINE ISOLATION				
a. Reactor Vessel Water Level				
1) Low, Low, Level 2	S	M	R	1, 2, 3
2) Low, Low, Low - Level 1	S	M	R	1, 2, 3
b. Main Steam Line Radiation - High	S	M	R	1, 2, 3
c. Main Steam Line Pressure - Low	S	M	R	1
d. Main Steam Line Flow - High	S	M	R	1, 2, 3
e. Condenser Vacuum - Low	S	M	R	1, 2**, 3**
f. Outboard MSIV Room Temperature - High	S	M	R	1, 2, 3
g. Turbine Enclosure - Main Steam Line Tunnel Temperature - High	S	M	R	1, 2, 3
h. Manual Initiation	N.A.	R	N.A.	1, 2, 3
2. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION				
a. Reactor Vessel Water Level Low - Level 3	S	M	R	1, 2, 3
b. Reactor Vessel (RHR Cut-In Permissive) Pressure - High	S	M	R	1, 2, 3
c. Manual Initiation	N.A.	R	N.A.	1, 2, 3

TABLE 4.3.2.1-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
3. REACTOR WATER CLEANUP SYSTEM ISOLATION				
a. RWCS Δ Flow - High	S	M	R	1, 2, 3
b. RWCS Area Temperature - High	S	M	R	1, 2, 3
c. RWCS Area Ventilation Δ Temperature - High	S	M	R	1, 2, 3
d. SLCS Initiation	N.A.	R	N.A.	1, 2, 3
e. Reactor Vessel Water Level - Low, Low, - Level 2	S	M	R	1, 2, 3
f. Manual Initiation	N.A.	R	N.A.	1, 2, 3
4. HIGH PRESSURE COOLANT INJECTION SYSTEM ISOLATION				
a. HPCI Steam Line Δ Pressure - High	S	M	R	1, 2, 3
b. HPCI Steam Supply Pressure - Low	S	M	R	1, 2, 3
c. HPCI Turbine Exhaust Diaphragm Pressure - High	S	M	R	1, 2, 3
d. HPCI Equipment Room Temperature - High	S	M	R	1, 2, 3
e. HPCI Equipment Room Δ Temperature - High	S	M	R	1, 2, 3
f. HPCI Pipe Routing Area Temperature - High	S	M	R	1, 2, 3
g. Manual Initiation	N.A.	R	N.A.	1, 2, 3
h. HPCI Steam Line Δ Pressure Timer	N.A.	M	R	1, 2, 3

REACTOR COOLANT SYSTEM

OPERATIONAL LEAKAGE

LIMITING CONDITION FOR OPERATION

3.4.3.2 Reactor coolant system leakage shall be limited to:

a. No PRESSURE BOUNDARY LEAKAGE.

b. 5 gpm UNIDENTIFIED LEAKAGE.

c. 30 gpm total leakage.

d. 25 gpm total leakage averaged over any 24-hour period.

e. 1 gpm leakage at a reactor coolant system pressure of 950 ±10 psig from any reactor coolant system pressure isolation valve specified in Table 3.4.3.2-1.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With any PRESSURE BOUNDARY LEAKAGE, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

b. With any reactor coolant system leakage greater than the limits in b, c, and/or d., above, reduce the leakage rate to within the limits within 4 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

c. With any reactor coolant system pressure isolation valve leakage greater than the above limit, isolate the high pressure portion of the affected system from the low pressure portion within 4 hours by use of at least one other closed manual, deactivated automatic, or check* valves, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

d. With one or more of the high/low pressure interface valve leakage pressure monitors shown in Table 3.4.3.2-1 inoperable, restore the inoperable monitor(s) to OPERABLE status within 7 days or verify the pressure to be less than the alarm setpoint at least once per 12 hours; restore the inoperable monitor(s) to OPERABLE status within 30 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

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*Which have been verified not to exceed the allowable leakage limit at the last refueling outage or after the last time the valve was disturbed, whichever is more recent.

SURVEILLANCE REQUIREMENTS

4.4.3.2.1 The reactor coolant system leakage shall be demonstrated to be within each of the above limits by:

a. Monitoring the primary containment atmospheric gaseous radioactivity at least once per 12 hours (not a means of quantifying leakage),

b. Monitoring the drywell floor drain sump and drywell equipment drain tank flow rate at least once per 12 hours,

c. Monitoring the drywell unit coolers condensate flow rate at least once per 12 hours,

d. Monitoring the primary containment pressure at least once per 12 hours (not a means of quantifying leakage),

e. Monitoring the reactor vessel head flange leak detection system at least once per 24 hours, and

f. Monitoring the primary containment temperature at least once per 24 hours (not a means of quantifying leakage).

4.4.3.2.2 Each reactor coolant system pressure isolation valve specified in Table 3.4.3.2-1 shall be demonstrated OPERABLE by leak testing pursuant to Specification 4.0.5 and verifying the leakage of each valve to be within the specified limit:

a. At least once per 18 months, and

b. Prior to returning the valve to service following maintenance, repair or replacement work on the valve which could affect its leakage rate.

The provisions of Specification 4.0.4 are not applicable for entry into OPERATIONAL CONDITION 3.

4.4.3.2.3 The high/low pressure interface valve leakage pressure monitors shall be demonstrated OPERABLE with alarm setpoints set less than the allowable values in Table 3.4.3.2-1 by performance of a:

a. CHANNEL FUNCTIONAL TEST at least once per 31 days, and

b. CHANNEL CALIBRATION at least once per 18 months.

3/4.6.6 PRIMARY CONTAINMENT ATMOSPHERE CONTROL

PRIMARY CONTAINMENT HYDROGEN RECOMBINER SYSTEMS

LIMITING CONDITION FOR OPERATION

3.6.6.1 Two independent primary containment hydrogen recombiner systems shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With one primary containment hydrogen recombiner system inoperable, restore the inoperable system to OPERABLE status within 30 days or be in at least HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.6.6.1 Each primary containment hydrogen recombiner system shall be demonstrated OPERABLE:

a. At least once per 6 months by performance of:

1. A CHANNEL CHECK of all Control Room Recombiner Instrumentation.
2. A Trickle Heat Circuit check.
3. A Heater Coil Check.
4. A verification of valve operation by stroking all the valves to their proper positions.

b. At least once per 18 months by:

1. Performing a CHANNEL CALIBRATION of all control room recombiner instrumentation and control circuits.
2. Verifying the integrity of all heater electrical circuits by performing a resistance to ground test within 30 minutes following the below required functional test. The resistance to ground for any heater phase shall be greater than or equal to one(1) megohm.
3. Verifying through a visual examination that there is no evidence of abnormal conditions within the recombiner enclosure; i.e., loose wiring or structural connections, deposits of foreign materials, etc.
4. Verifying during a recombiner system functional test that the minimum heater outlet gas temperature increases to greater than or equal to 1150°F within 120 minutes and maintained for at least one hour.

c. By measuring the system leakage rate:

1. As a part of the overall integrated leakage rate test required by Specification 3.6.1.2, or
2. By measuring the leakage rate of the system outside of the containment isolation valves at P_a, 44.0 psig, on the schedule required by Specification 4.6.1.2, and including the measured leakage as a part of the leakage determined in accordance with Specification 4.6.1.2.

DRYWELL HYDROGEN MIXING SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.6.2 Four independent drywell unit cooler hydrogen mixing subsystems (1AV212, 1BV212, 1GV212, 1HV212) shall be OPERABLE with each subsystem consisting of one unit cooler fan.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2

ACTION:

With one drywell unit cooler hydrogen mixing subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 30 days or be in at least HOT SHUTDOWN within the next 12 hou

SURVEILLANCE REQUIREMENTS

4.6.6.2 Each drywell unit cooler hydrogen mixing subsystem shall be demonstrated OPERABLE at least once per 92 days by:

a. Starting the system from the control room, and

b. Verifying that the system operates for at least 15 minutes.

e. Functional Tests

During the first refueling shutdown and at least once per 18 months thereafter, a representative sample of snubbers shall be tested using one of the following sample plans for each type of snubber. The sample plan shall be selected prior to the test period and cannot be changed during the test period. The NRC Regional Administrator shall be notified in writing of the sample plan selected prior to the test period or the sample plan used in the prior test period shall be implemented:

1) At least 10% of the total of each type of snubber shall be functionally tested either in-place or in a bench test. For each snubber of a type that does not meet the functional test acceptance criteria of Specification 4.7.4f., an additional 10% of that type of snubber shall be functionally tested until no more failures are found or until all snubbers of that type have been functionally tested; or

2) A representative sample of each type of snubber shall be functionally tested in accordance with Figure 4.7.4-1. "C" is the total number of snubbers of a type found not meeting the acceptance requirements of Specification 4.7.4f. The cumulative number of snubbers of a type tested is denoted by "N". At the end of each day's testing, the new values of "N" and "C" (previous day's total plus current day's increments) shall be plotted on Figure 4.7.4-1. If at any time the point plotted falls on or above the "Reject" line all snubbers of that type shall be functionally tested. If at any time the point plotted falls on or below the "Accept" line, testing of snubbers of that type may be terminated. When the point plotted lies in the "Continue Testing" region, additional snubbers of that type shall be tested until the point falls in the "Accept" region or the "Reject" region, or all the snubbers of that type have been tested. Testing equipment failure during functional testing may invalidate that day's testing and allow that day's testing to resume anew at a later time, providing all snubbers tested with the failed equipment during the day of equipment failure are retested; or

3) An initial representative sample of 55 snubbers of each type shall be functionally tested. For each snubber type which does not meet the functional test acceptance criteria, another sample of at least one-half the size of the initial sample shall be tested until the total number tested is equal to the initial sample size multiplied by the factor, 1 + C/2, where "C" is the number of snubbers found which do not meet the functional test acceptance criteria. The results from this sample plan shall be plotted using an "Accept" line which follows the equation N = 55(1 + C/2). Each snubber point should be plotted as soon as the snubber is tested. If the point plotted falls on or below the "Accept" line, testing of that type of snubber may be terminated. If the point plotted falls above the "Accept" line, testing must continue until the point falls on or below the "Accept" line or all the snubbers of that type have been tested.

SURVEILLANCE REQUIREMENTS (Continued)

The representative sample selected for the function test sample plans shall be randomly selected from the snubbers of each type and reviewed before beginning the testing. The review shall ensure as far as practical that they are representative of the various configurations, operating environments, range of size, and capacity of snubbers of each type. Snubbers placed in the same locations as snubbers which failed the previous functional test shall be retested at the time of the next functional test but shall not be included in the sample plan, and failure of this functional test shall not be the sole cause for increasing the sample size under the sample plan. If during the functional testing, additional sampling is required due to failure of only one type of snubber, the functional testing results shall be reviewed at the time to determine if additional samples should be limited to the type of snubber which has failed the functional testing.

f. Functional Test Acceptance Criteria

The snubber functional test shall verify that:

1) Activation (restraining action) is achieved within the specified range in both tension and compression;

2) Snubber bleed, or release rate where required, is present in both tension and compression, within the specified range (hydraulic snubbers only);

3) For mechanical snubbers, the force required to initiate or maintain motion of the snubber is within the specified range in both directions of travel; and

4) For snubbers specifically required not to displace under continuous load, the ability of the snubber to withstand load without displacement.

Testing methods may be used to measure parameters indirectly or parameters other than those specified if those results can be correlated to the specified parameters through established methods.

g. Functional Test Failure Analysis

An engineering evaluation shall be made of each failure to meet the functional test acceptance criteria to determine the cause of the failure. The results of this evaluation shall be used, if applicable, in selecting snubbers to be tested in an effort to determine the OPERABILITY of other snubbers irrespective of type which may be subject to the same failure mode.

For the snubbers found inoperable, an engineering evaluation shall be performed on the components to which the inoperable snubbers are attached. The purpose of this engineering evaluation shall be to determine if the components to which the inoperable snubbers are attached were adversely affected by the inoperability of the snubbers in order to ensure that the component remains capable of meeting the designed service.

TABLE 6.2.2-1

MINIMUM SHIFT CREW COMPOSITION

TWO UNITS WITH A COMMON CONTROL ROOM

WITH UNIT (2) IN CONDITION 4 OR 5 OR DEFUELED

POSITION	NUMBER OF INDIVIDUALS REQUIRED TO FILL POSITION	
	CONDITION 1, 2, or 3	CONDITION 4 or 5
SS	1*	1*
SRO	1*	1*
RO	2	1
NLO	2	2**
STA	1	None

WITH UNIT (2) IN CONDITION 1, 2, OR 3

POSITION	NUMBER OF INDIVIDUALS REQUIRED TO FILL POSITION	
	CONDITION 1, 2, or 3	CONDITION 4 or 5
SS	1*	1*
SRO	1*	1*
RO	2**	1
NLO	2**	1
STA	1*	None

TABLE NOTATIONS

*Individual may fill the same position on Unit 2.
**One of the two required individuals may fill the same position on Unit 2.

SS - Shift Superintendent or Shift Supervisor with a Senior Operator license on Unit 1.
SRO - Individual with a Senior Operator license on Unit 1.
RO - Individual with an Operator license on Unit 1.
NLO - Non-licensed operator properly qualified to support the unit to which assigned.
STA - Shift Technical Advisor

Except for Shift Supervision (SS), the shift crew composition may be one less than the minimum requirements of Table 6.2.2-1 for a period of time not to exceed 2 hours in order to accommodate unexpected absence of on-duty shift crew members provided immediate action is taken to restore the shift crew composition to within the minimum requirements of Table 6.2.2-1. This provision does not permit any shift crew position to be unmanned upon shift change due to an oncoming shift crewman being late or absent.

During any absence of Shift Supervision (SS) from the control room while the unit is in OPERATIONAL CONDITION 1, 2, or 3, an individual (other than the Shift Technical Advisor) with a valid Senior Operator license shall be designated to assume the control room command function. During any absence of Shift Supervision from the control room while the unit is in OPERATIONAL CONDITION 4 or 5, an individual with a valid Senior Operator license or Operator license shall be designated to assume the control room command function.

6.2.3 INDEPENDENT SAFETY ENGINEERING GROUP (ISEG)

FUNCTION

6.2.3.1 The ISEG shall function to examine unit operating characteristics, NRC issuances, industry advisories, Licensee Event Reports, and other sources of unit design and operating experience information, including units of similar design, which may indicate areas for improving unit safety. The ISEG shall make detailed recommendations for revised procedures, equipment modifications, maintenance activities, operations activities, or other means of improving unit safety. Such recommendations shall be submitted through the General Manager-Nuclear Quality Assurance to the Senior Vice President-Nuclear.

COMPOSITION

6.2.3.2 The Limerick ISEG shall be composed of at least three, dedicated, full-time engineers, including the ISEG Supervisor, located onsite. Each shall have a bachelor's degree in engineering or related science and at least two years professional level experience in his or her field. The Limerick ISEG Supervisor shall have at least six years of experience in the nuclear field. The corporate ISEG shall be composed of two dedicated full time engineers each with a Bachelors degree in engineering or related science and at least 2 years professional level experience in his or her field, at least 1 year of which experience shall be in the nuclear field. The LGS ISEG reports to the Independent Safety Engineering Manager.

RESPONSIBILITIES

6.2.3.3 The ISEG shall be responsible for maintaining surveillance of unit activities to provide independent verification* that these activities are performed correctly and that human errors are reduced as much as practical.

RECORDS

6.2.3.4 Records of activities performed by the ISEG shall be prepared, maintained, and forwarded each calendar month to the Independent Safety Engineering Manager.

6.2.4 SHIFT TECHNICAL ADVISOR

6.2.4.1 The Shift Technical Advisor shall provide advisory technical support to Shift Supervision in the areas of thermal hydraulics, reactor engineering, and plant analysis with regard to safe operation of the unit. The Shift Technical Advisor shall have a bachelor's degree or equivalent in a scientific or engineering discipline and shall have received specific training in the response and analysis of the unit for transients and accidents, and in unit design and layout, including the capabilities of instrumentation and controls in the control room.

6.3 UNIT STAFF QUALIFICATIONS

6.3.1 Each member of the unit staff shall meet or exceed the minimum qualifications of ANSI/ANS 3.1-1978 for comparable positions, except for the Senior Health Physicist who shall meet or exceed the qualifications of Regulatory Guide 1.8, September 1975. The licensed Operators and Senior Operators shall also meet or exceed the minimum qualifications of the supplemental requirements specified in Sections A and C of Enclosure 1 of the March 28, 1980 NRC letter to all licensees.

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*Not responsible for sign-off function.