CPSES UNIT 1
NRC DOCKET NO. 50-445
LICENSE AMENDMENT REQUEST 91-003

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Significant Hazards Consideration
Proposed Unit 1 Technical Specification Change
Various RPS and ESF Action
and Surveillance Requirements

I. DESCRIPTION

This change proposes to modify the Comanche Peak Steam Electric Station Unit 1 Technical Specifications by relaxing the Allowed Outage Times (AOT) and the Surveillance Test Intervals (STI) for Analog Channels shared by both the Reactor Protection System (RPS) and the Engineered Safety Features Actuation System (ESFAS).

II. BACKGROUND

In response to the high number of reactor trips and Engineered Safety Features Actuation System (ESFAS) actuations experienced by plants as a result of instrument testing and surveillance activities, the Westinghouse Owners Group (WOG) initiated a program to develop generic justification for revising generic and plant specific instrumentation technical specifications to reduce the test and maintenance requirements.

As a result of the WOG submittals, the NRC, in the following correspondence, approved almost all the relaxations suggested by the WOG.

* Letter C. O. Thomas (NRC) to J. J. Shepperd (WOG) dated February 21, 1985 (NRC Safety Evaluation for WCAP-10271)
* Letter Charles E. Rossi (NRC) to Roger A. Newton (WOG) dated February 22, 1989 (NRC Safety Evaluation for WCAP-10271 Supplement 2 and Supplement 2 Revision 1)
* Letter Charles E. Rossi (NRC) to Gerald T. Goering (WOG) dated April 30, 1990 (NRC Supplemental Safety Evaluation for WCAP-10271 Supplement 2 and Supplement 2 Revision 1)

CPSES incorporated most of the suggested STI and AOT relaxations in the original Technical Specifications issued on February 1990; however, in the months prior to license issuance and during Technical Specification development, all review and acceptance of the Westinghouse Owners Group submittal of WCAP-10271 (and supplements) was not completed. As a result, most, but not all provisions of WCAP-10271 (and supplements) were incorporated. This change proposes to incorporate the remainder of the changes. This request is being made under the generic justification provided by Westinghouse Electric Corporation during approval of WCAP-10271 Supplement 2, and Supplement 2 Revision 1.

III. JUSTIFICATION

An increase in the allowed outage time for maintenance will allow better more deliberate testing and repair, thus reducing the potential for human error and reducing vulnerability of CPSES to the high trip rate experienced by other operating plants.

The changes A, B, C, and D, listed in Part V of this enclosure, result directly from the completion of a Westinghouse Owners Group (WOG) evaluation of Surveillance Test Intervals (STI) and Allowed Outage Times (AOT) and their effect on nuclear safety. Changes E and F listed in Part V of this enclosure result from a supplemental study of the Reactor Water Storage Tank (RWST) level unavailability performed specifically for CPSES (WCAP-10271, Supplement 3). WCAP 10271 Supplement 3 was transmitted to the NRC from TU Electric via letter logged TXX-91069 and dated March 5, 1991.

Several administrative changes are proposed, as listed below:

1. Update the BASES section at page B 3/4 3-1 to reflect the NRCs supplemental safety evaluation of WCAP-10271 and its supplements.

2. Reword action statements requiring the plant to be in HOT STANDBY in 12 hours to allow 6 hours to restore the inoperable channel, then 6 hours to be in HOT STANDBY (same total length of time). This will avoid the incorrect perception of being in a shutdown action statement which has reportability and emergency classification connotations.

3. Renumber action statements to prevent human error. This change avoids two "Action 12's" and renumbers the Action Statements of Table 3.3-2.

4. Delete reference to STARTUP and/or POWER OPERATION (MODES 2 and/or 1) in Action 17 and 23 and replace with "Operation", similar to the wording used in Action 14. The LCO to which these Actions apply include Applicable Modes beyond MODES 1 and 2 (1, 2; 1, 2, 3; and 1, 2, 3, 4). This change avoids confusion when the plant is in MODES 3 or 4 and the Action is entered.

5. Deletes note "e" of table 3.3-1. The note is no longer applicable since as a result of the WCAP 10271 and its supplements the AOT instruments common to RPS and ESFAS do not have differing RPS and ESF requirements.

IV. SAFETY EVALUATION

In WCAP-10271 including supplements 1, and 2, the WOG evaluated the impact of the proposed STI and AOT changes on core damage frequency and public risk. The NRC staff concludes in its evaluation of the WOG submittal that an overall upper bound increase of the core damage frequency due to the proposed STI/AOT changes is less than 6 percent for Westinghouse Pressurized Water Reactor (PWR) plants. The NRC Staff also concluded that actual core damage frequency increases for individual plants are expected to be substantially less than 6 percent. The NRC Staff considered this core damage frequency increase to be small compared to the range of uncertainty in the core damage frequency analyses and therefore acceptable.

In WCAP-10271 Supplement 3, the Reactor Water Storage Tank (RWST) level channels were evaluated and found to be identical in configuration to the Steam Generator level channel and therefore the RWST level channels would be bounded by the unavailability analysis for the Steam Generator level channel.

The proposed changes are consistent with the NRC Staff's letters dated February 22, 1989, and April 30, 1990, to the WOG regarding evaluation of WCAP-10271, WCAP-10271 Supplement 1, WCAP-10271 Supplement 2 and WCAP-10271 Supplement 2, Revision 1. The Staff has stated that approval of these changes at a particular plant will be contingent upon confirmation that certain conditions are met. CPSES compliance with these conditions is provided below:

1. <u>Common cause evaluation of plant protection system failures</u>. CPSES has previously implemented quarterly surveillance intervals except for RWST level. Quarterly Surveillance of the RWST level is included in this proposed change to the technical specifications. Plant programs and procedures are in place and being used to evaluate failures, trend failures, and perform common mode failure evaluation when necessary. Evaluation and reporting under the Nuclear Plant Reliability Data System (NPRDS) are included in these programs.

2. <u>Testing of analog channels in bypass</u>. Testing of analog channels, described in FSAR 7.2.2.2.3 and 7.3.2.2.5, is done with the channels in the trip condition except for containment spray actuation which is an energize to actuate channel and therefore designed to be tested in bypass. Jumpers and lifted leads are not used for this testing.

3. Setpoint drift. CPSES implemented quarterly analog testing upon receipt of the operating license in February 1990, except for RWST level as noted above. The setpoint methodology contains adequate allowance to bound anticipated drift over a three month period. Additionally, setpoint drift data has been trended since prior to licensing to confirm this allowance. No excessive drift has been noted over this period.

4. Applicability of Generic Analysis to CPSES. CPSES is a 4-loop Westinghouse PWR with a Solid State Protection System. As described in WCAP-10271 and its supplements, all changes proposed in this amendment are addressed by the generic analysis except for RWST level. RWST level was separately evaluated on a plant specific basis in WCAP-10271 Supplement 3. This amplified the analysis presented in the other supplements to encompass RWST level. This analysis concluded that RWST level is identical in configuration to the steam generator level channel; therefore, the system unavailabilities resulting from relaxed STIs and AOTs were essentially the same and will have no impact on plant safety.

V. DETAILED DISCUSSION

The requested amendment revises several aspects of the Reactor Protection System (RPS) and Engineered Safety Features (ESF) of Technical Specifications 3.3.1 and 3.3.2. These changes include the following:

A. Added new Action 13 (Table 3.3-1) applicable to safety injection input from ESFAS and automatic trip and interlock logic allowing for 12 hours maintenance AOT and 4 hours surveillance AOT.

B. Changed Actions 12 (Table 3.3-1) and Actions 19, 22, and 26 (original Action 12) (Table 3.3-2) to increase the Allowed Outage Time (AOT) for Surveillance Test to 4 hours.

C. Replaced original Action 13 with Action 17 for 3 channel systems (Table 3.3-2), to allow the same provisions as 4 channel systems.

D. Revised note "e" of Table 3.3-2 to make the time allowed to place the Steam Generator High Level channel into trip and the Surveillance AOT consistent with the provisions for inoperable channels (Action 17).

E. Revised test frequency for the RWST Low Low level to Quarterly (Table 4.3-2).

F. Revised Action for RWST Low Low Level from 26 to 17 (Table 3.3-2).

G. Administrative changes as follows:

1. Updated BASES reference to include the latest SERs.

2. Actions 13 (new) (Table 3.3-1), and Actions 19, 22, and 26 (new) (Table 3.3-2) have been revised to break the 12 hour shutdown time requirement into the more standard 6 hours to restore or be in at least HOT STANDBY within the next 6 hours.

3. Deleted Actions 13 and 26 (Table 3.3-2) that were no longer used, and re-numbered original ESF Action 12 to new Action 26. This avoids the two "Action 12's" that previously existed. Renumbered Actions on Table 3.3-2 accordingly.

4. Revised Actions 17 and 23 to delete specific reference to STARTUP and/or POWER OPERATION (MODES 1 and/or 2) and apply broader term of "operation".

5. Deleted Note "e" on Table 3.3-1 for Pressurizer Pressure Low and Steam Generator Water Level Low Low.

VI. PRECEDENTS

The changes proposed by this License Amendment Request (with the exception of the RWST changes) have been accepted by the NRC in the correspondence listed in part II above. The proposed changes to the RWST, although not specifically accepted, have been evaluated and found to be identical and thus bounded by the Steam Generator Level unavailability analysis which has been accepted by the NRC. Other changes also accepted in that listed correspondence were incorporated into the CPSES Technical Specifications prior to their issuance in February, 1990.

VII. NO SIGNIFICANT HAZARDS CONSIDERATION EVALUATION PER 10CFR50.92

The standards used to arrive at a proposed determination that the changes described involve no significant hazards consideration are included in 10CFR50.92. The regulations state that if operation of the facility in accordance with the proposed amendment would not; (1) involve a significant increase in the probability or consequences of an accident previously evaluated, or (2) create the possibility of a new or different kind of accident from any accident previously evaluated, or (3) involve a significant reduction in a margin of safety then a no significant hazards consideration determination can be made.

CPSES has reviewed the requirements of 10CFR50.92 as they relate to the proposed RPS and ESFAS Technical Specification changes for CPSES and determined that a significant hazards consideration is not involved. In support of this conclusion,the following analyses are provided.

Criterion 1 -

The determination that the results of the proposed changes are within all acceptable criteria was established in the SER(s) prepared for WCAP-10271 Supplement 2 and WCAP-10271 Supplement 2, Revision 1 issued by letters dated February 22, 1989 and April 30, 1990. Implementation of the proposed changes is expected to result in an acceptable increase in total Reactor Protection System and Engineered Safety Features Actuation System unavailability. This increase results in a small increase in core damage frequency (CDF) and public health risk. The values determined by the WOG and presented in the WCAP for the increase in CDF were verified by Brookhaven National Laboratory (BNL) as part of an audit and sensitivity analyses for the NRC Staff. Based on the small value for the increase compared to the range of uncertainty in the CDF, the increase is considered acceptable. The extension of the WOG relaxations to the RWST level has been separately shown to be bounded by the increased CDF resulting from relaxation of the Steam Generator Level channel and therefore should be acceptable on the same basis.

The proposed changes do not result in an increase in the severity or consequences of an accident previously evaluated. Implementation of the proposed changes affects the probability of failure of the RPS or ESF but does not alter the manner in which protection is afforded nor the manner in which limiting criteria are established.

Operation of CPSES in accordance with the proposed license amendment does not involve a significant increase in the probability or consequences of an accident previously evaluated.

Criterion 2 -

The proposed changes do not involve hardware changes and do not result in a change in the manner in which the Protection System provides plant protection. No change is being made which alters the functioning of the Protection System. Rather the likelihood or probability of the Protection System functioning properly is affected as described above. Therefore the proposed changes do not create the possibility of a new or different kind of accident.

Crit-- on 3 -

The proposed changes do not alter the manner in which safety limits, limiting safety system setpoints or limiting conditions for operation are determined. The impact of reduced testing other than addressed above is to allow a longer time interval over which instrument uncertainties (e.g., drift) may act. Experience has shown that the initial uncertainty assumptions are valid for reduced testing.

Implementation of the proposed changes is expected to result in an overall improvement in safety due to:

a. Less frequent testing which will result in fewer inadvertent reactor trips and actuations of the Engineered Safety Features Actuation System components.

b. Improvements in the effectiveness of the operating staff in monitoring and controlling plant operation. This is due to less frequent distraction of the operator and shift supervisor to attend to instrumentation testing.

The foregoing analysis demonstrates that the proposed amendment to CPSES technical specifications does not involve a significant increase in the probability or consequences of a previously evaluated accident, does not create the possibility of a new or different kind of accident and does not involve a significant reduction in a margin of safety.

VIII. NO SIGNIFICANT HAZARDS CONSIDERATION DETERMINATION

The Commission has provided guidance concerning the application of the standards for determining whether a significant hazards consideration exists by providing certain examples (51 FR 7751) of amendments that are considered not likely to involve significant hazards consideration. Example (i) relates to a purely administrative change to Technical Specifications: for example, a change to achieve consistency throughout the Technical Specifications, correction of an error, or a change in nomenclature. Example (vi) relates to a change which either may result in some increase to the probability or consequences of a previously-analyzed accident or may reduce in some way a safety margin, but where the results of the change are clearly within all acceptable criteria with respect to the system or component specified in the Standard Review Plan; for example, a change resulting from the application of a small refinement of a previously used calculational model or design method.

In this case, the change request described above is similar to Example (i) in that it is partially an administrative change to achieve consistency throughout the Technical Specifications.

Additionally it is similar to Example (vi) in that portions may result in some increase to the probability of a previously analyzed accident, but the increase is not significant compared to the range of uncertainty of the analysis and therefore is considered acceptable. Based upon the preceding analysis, CPSES concludes that the proposed amendment does not involve a significant hazards consideration.

IX. ENVIRONMENTAL EVALUATION

TU Electric has evaluated the proposed changes and has determined that the changes do not involve (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amounts of any effluent that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed changes meet the eligibility criterion for categorical exclusion set forth in 10CFR51.22(c)(9). Therefore, pursuant to 10CFR51.22(b), an environmental assessment of the proposed changes is not required.

X. REFERENCES

1. CPSES Unit 1 Technical Specifications
2. WCAP-10271 Supplement 1, Supplement 2, Supplement 2 Revision 1, and Supplement 3.

INSTRUCTIONS FOR INCORPORATION

REMOVE	INSERT
page 3/4 3-1 thru 3/4 3-8	page 3/4 3-1 thru 3/4 3-8
page 3/4 3-15 thru 3/4 3-24	page 3/4 3-15 thru 3/4 3-24
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page B 3/4 3-1 thru B 3/4 3-2	page B 3/4 3-1 thru B 3/4 3-2

3/4.3 INSTRUMENTATION

3/4.3.1 REACTOR TRIP SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.1 As a minimum, the Reactor Trip System instrumentation channels and interlocks of Table 3.3-1 shall be OPERABLE.

APPLICABILITY: As shown in Table 3.3-1.

ACTION:

As shown in Table 3.3-1.

SURVEILLANCE REQUIREMENTS

4.3.1.1 Each Reactor Trip System instrumentation channel and interlock and the automatic trip logic shall be demonstrated OPERABLE by the performance of the Reactor Trip System Instrumentation Surveillance Requirements specified in Table 4.3-1.

4.3.1.2 The REACTOR TRIP SYSTEM RESPONSE TIME of each Reactor trip function shall be demonstrated to be within its' limit at least once per 18 months. Each test shall include at least one train such that both trains are tested at least once per 36 months and one channel per function 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 function as shown in the "Total No. of Channels" column of Table 3.3-1.

TABLE 3.3-1

REACTOR TRIP SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
1. Manual Reactor Trip	2	1	2	1, 2	1
	2	1	2	3^{a}, 4^{a}, 5^{a}	9
2. Power Range, Neutron Flux					
a. High Setpoint	4	2	3	1, 2	2
b. Low Setpoint	4	2	3	1^{c}, 2	2
3. Power Range, Neutron Flux High Positive Rate	4	2	3	1, 2	2
4. Power Range, Neutron Flux, High Negative Rate	4	2	3	1, 2	2
5. Intermediate Range, Neutron Flux	2	1	2	1^{c}, 2	3
6. Source Range, Neutron Flux					
a. Reactor Trip and Indication					
1) Startup	2	1	2	2^{b}	4
2) Shutdown	2	1	2	3, 4, 5	5
b. Boron Dilution Flux Doubling	2	1	2	3^{h}, 4, 5	5
7. Overtemperature N-16	4	2	3	1, 2	12
8. Overpower N-16	4	2	3	1, 2	12
9. Pressurizer Pressure--Low	4	2	3	1^{d}	6
10. Pressurizer Pressure--High	4	2	3	1, 2	6

TABLE 3.3-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
11. Pressurizer Water Level--High	3	2	2	1^d	6
12. Reactor Coolant Flow--Low					
a. Single Loop	3/loop	2/loop in any loop	2/loop	1^f	6
b. Two Loops	3/loop	2/loop in any two loops	2/loop	1^g	6
13. Steam Generator Water Level--Low-Low	4/stm. gen.	2/stm. gen. in any stm. gen.	3/stm. gen.	1, 2	6
14. Undervoltage--Reactor Coolant Pumps	4-1/bus	2	3	1^d	6
15. Underfrequency--Reactor Coolant Pumps	4-1/bus	2	3	1^d	6
16. Turbine Trip					
a. Low Fluid Oil Pressure	3	2	2	1^i	6
b. Turbine Stop Valve Closure	4	4	4	1^i	10
17. Safety Injection Input from ESFAS	2	1	2	1, 2	13

TABLE 3.3-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
18. Reactor Trip System Interlocks					
a. Intermediate Range Neutron Flux, P-6	2	1	2	2^{b}	7
b. Low Power Reactor Trips Block, P-7					
1) P-10 Input	4	2	3	1, 2	7
2) P-13 Input	2	1	2	1	7
c. Power Range Neutron Flux, P-8	4	2	3	1	7
d. Power Range Neutron Flux, P-9	4	2	3	1^{f}	7
e. Power Range Neutron Flux, P-10	4	2	3	1, 2	7
19. Reactor Trip Breakers	2	1	2	1, 2	8, 11
	2	1	2	3^{a}, 4^{a}, 5^{a}	9
20. Automatic Trip and Interlock Logic	2	1	2	1, 2	13
	2	1	2	3^{a}, 4^{a}, 5^{a}	9

TABLE 3.3-1 (Continued)

TABLE NOTATIONS

[a]Only if the reactor trip breakers happen to be in the closed position and the Control Rod Drive System is capable of rod withdrawal.

[b]Below the P-6 (Intermediate Range Neutron Flux Interlock) Setpoint.

[c]Below the P-10 (Low Setpoint Power Range Neutron Flux Interlock) Setpoint.

[d]Above the P-7 (At Power) Setpoint

e deleted

[e]~~The applicable MODES and ACTION statements for these channels noted in~~ Table 3.3-2 are more restrictive and therefore, applicable.

[f]Above the P-8 (3-loop flow permissive) Setpoint.

[g]Above the P-7 and below the P-9 Setpoints.

[h]The boron dilution flux doubling signals may be blocked during reactor startup.

[i]Above the P-9 (Reactor trip on Turbine trip Interlock) Setpoint

ACTION STATEMENTS

ACTION 1 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 48 hours or be in HOT STANDBY within the next 6 hours.

ACTION 2 - With the number of OPERABLE channels one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed provided the following conditions are satisfied:

a. The inoperable channel is placed in the tripped condition within 6 hours,

b. The Minimum Channels OPERABLE requirement is met; however, the inoperable channel may be bypassed for up to 4 hours for surveillance testing of other channels per Specification 4.3.1.1, and

c. Either, THERMAL POWER is restricted to less than or equal to 75% of RATED THERMAL POWER and the Power Range Neutron Flux Trip Setpoint is reduced to less than or equal to 85% of RATED THERMAL POWER within 4 hours; or, the QUADRANT POWER TILT RATIO is monitored at least once per 12 hours per Specification 4.2.4.2.

TABLE 3.3-1 (Continued)

ACTION STATEMENTS (Continued)

ACTION 3 - With the number of channels OPERABLE one less than the Minimum Channels OPERABLE requirement and with the THERMAL POWER level:

a. Below the P-6 (Intermediate Range Neutron Flux Interlock) Setpoint, restore the inoperable channel to OPERABLE status prior to increasing THERMAL POWER above the P-6 Setpoint.

b. Above the P-6 (Intermediate Range Neutron Flux Interlock) Setpoint but below 10% of RATED THERMAL POWER, restore the inoperable channel to OPERABLE status prior to increasing THERMAL POWER above 10% of RATED THERMAL POWER.

ACTION 4 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, suspend all operations involving positive reactivity changes.

ACTION 5 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 48 hours or within the next hour open the reactor trip breakers, suspend all operations involving positive reactivity changes and verify either valve 1CS-8455 or valves 1CS-8560, FCV-111B, 1CS-8439, 1CS-8441, and 1CS-8453 are closed and secured in position, and verify this position at least once per 14 days thereafter. With no channels OPERABLE complete all the above actions within 4 hours and verify the positions of the above valves at least once per 14 days thereafter.

ACTION 6 - With the number of OPERABLE channels one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed provided the following conditions are satisfied:

a. The inoperable channel is placed in the tripped condition within 6 hours, and

b. The Minimum Channels OPERABLE requirement is met; however, the inoperable channel may be bypassed for up to 4 hours for surveillance testing of other channels per Specification 4.3.1.1.

ACTION 7 - With less than the Minimum Number of Channels OPERABLE, within 1 hour determine by observation of the associated permissive annunciator window(s) that the interlock is in its required state for the existing plant condition, or apply Specification 3.0.3.

TABLE 3.3-1 (Continued)

ACTION STATEMENTS (Continued)

ACTION 8 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, be in at least HOT STANDBY within 6 hours; however, one channel may be bypassed for up to 2 hours for surveillance testing per Specification 4.3.1.1 or maintenance, provided the other channel is OPERABLE.

ACTION 9 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 48 hours or open the reactor trip breakers within the next hour.

ACTION 10 - With the number of OPERABLE channels less than the Total Number of Channels, operation may continue provided the inoperable channels are placed in the tripped condition within 6 hours.

ACTION 11 - With one of the diverse trip features (undervoltage or shunt trip attachment) inoperable, restore it to OPERABLE status within 48 hours or declare the breaker inoperable and apply ACTION 8. The breaker shall not be bypassed while one of the diverse trip features is inoperable except for the time required for performing maintenance to restore the breaker to OPERABLE status, during which time ACTION 8 applies.

ACTION 12 - With the number of OPERABLE channels one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed provided the following conditions are satisfied:

a. The inoperable channel is placed in the tripped condition within 6 hours, and

b. The Minimum Channels OPERABLE requirement is met; however, the inoperable channel may be bypassed for up to 4 hours for surveillance testing per Specifications 4.3.1.1 or 4.2.5.4.

Action 13 - With the number of OPERABLE Channels one less than the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 6 hours or be in at least HOT STANDBY within the next 6 hours; however, one channel may be bypassed for up to 4 hours for surveillance testing per Specification 4.3.1.1, provided the other channel is OPERABLE.

TABLE 4.3-1

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
1. Manual Reactor Trip	N.A.	N.A.	N.A.	R(14)	N.A.	1, 2, 3[a], 4[a], 5[a]
2. Power Range, Neutron Flux						
a. High Setpoint	S	D(2, 4), M(3, 4), Q(4, 6), R(4, 5)	Q	N.A.	N.A.	1, 2
b. Low Setpoint	S	R(4)	S/U(1)	N.A.	N.A.	1[c], 2
3. Power Range, Neutron Flux, High Positive Rate	N.A.	R(4)	Q	N.A.	N.A.	1, 2
4. Power Range, Neutron Flux, High Negative Rate	N.A.	R(4)	Q	N.A.	N.A.	1, 2
5. Intermediate Range, Neutron Flux	S	R(4, 5)	S/U(1)	N.A.	N.A.	1[c], 2
6. Source Range, Neutron Flux	S	R(4, 13)	S/U(1), Q(9)	R(12)	N.A.	2[b], 3, 4, 5
7. Overtemperature N-16	S	D(2, 4) M(3, 4) Q(4, 6) R(4, 5)	Q	N.A.	N.A.	1, 2
8. Overpower N-16	S	D(2, 4) R(4, 5)	Q	N.A.	N.A.	1, 2
9. Pressurizer Pressure--Low	S	R	Q(8)	N.A.	N.A.	1[d]
10. Pressurizer Pressure--High	S	R	Q	N.A.	N.A.	1, 2

TABLE 3.3-2

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
1. Safety Injection (ECCS, Reactor Trip, Feedwater Isolation, Control Room Emergency Recirculation, Emergency Diesel Generator Operation, Containment Vent Isolation, Station Service Water, Phase A Isolation, Auxiliary Feedwater-Motor Driven Pump, Turbine Trip, Component Cooling Water, Essential Ventilation Systems, and Containment Spray Pump.					
a. Manual Initiation	2	1	2	1, 2, 3, 4	16
b. Automatic Actuation Logic and Actuation Relays	2	1	2	1, 2, 3, 4	26
c. Containment Pressure--High-1	3	2	2	1, 2, 3	17
d. Pressurizer Pressure--Low	4	2	3	1, 2, 3^a	17
e. Steam Line Pressure--Low	3/steam line	2/steam line in any steam line	2/steam line	1, 2, 3^a	17

TABLE 3.3-2 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
2. Containment Spray					
a. Manual Initiation	2 pair	1 pair operated simultaneously	2 pair	1, 2, 3, 4	16
b. Automatic Actuation Logic and Actuation Relays	2	1	2	1, 2, 3, 4	26
c. Containment Pressure--High-3	4	2	3	1, 2, 3	14
3. Containment Isolation					
a. Phase "A" Isolation					
1) Manual Initiation	2	1	2	1, 2, 3, 4	16
2) Automatic Actuation Logic and Actuation Relays	2	1	2	1, 2, 3, 4	26
3) Safety Injection	See Item 1. above for all Safety Injection initiating functions and requirements.				
b. Phase "B" Isolation					
1) Manual Initiation	See Item 2.a above. Phase "B" isolation is manually initiated when containment spray function is manually initiated.			1, 2, 3, 4	16
2) Automatic Actuation Logic and Actuation Relays	2	1	2	1, 2, 3, 4	26
3) Containment Pressure--High-3	4	2	3	1, 2, 3	14

TABLE 3.3-2 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
c. Containment Vent Isolation					
1) Manual Initiation	See Item 2.a and 3.a.1 above. Containment vent isolation is manually initiated when Phase "A" isolation function or containment spray function is manually initiated.			1, 2, 3, 4	15
2) Automatic Actuation Logic and Actuation Relays	2	1	2	1, 2, 3, 4	15
3) Safety Injection	See Item 1. above for all Safety Injection initiating functions and requirements.				
4. Steam Line Isolation					
a. Manual Initiation					
1) Individual Steam Line	1/steam line	1/steam line	1/operating steam line	1, $2^{\#}$, $3^{\#}$	21
2) System	2	1	2	1, $2^{\#}$, $3^{\#}$	20
b. Automatic Actuation Logic and Actuation Relays	2	1	2	1, $2^{\#}$, $3^{\#}$	19
c. Containment Pressure--High-2	3	2	2	1, $2^{\#}$, $3^{\#}$	17

TABLE 3.3-2 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
4. Steam Line Isolation (Continued)					
d. Steam Line Pressure--Low	3/steam line	2/steam line in any steam line	2/steam line	1, 2[c], 3[a,c]	17
e. Steam Line Pressure - Negative Rate--High	3/steam line	2/steam line in any steam line	2/steam line	3[b,c]	17
5. Turbine Trip and Feedwater Isolation					
a. Automatic Actuation Logic and Actuation Relays	2	1	2	1, 2	22
b. Steam Generator Water Level--High-High	3/stm. gen.[e]	2/stm. gen. in any stm. gen.	2/stm. gen.	1, 2	17
c. Safety Injection	See Item 1 [illegible] all Safety Injection initiating functions and requirements.				
6. Auxiliary Feedwater					
a. Automatic Actuation Logic and Actuation Relays	2	1	2	1, 2, 3	19
b. Stm. Gen. Water Level--Low-Low					
1) Start Motor-Driven Pumps	4/stm. gen.	2/stm. gen. in any operating stm. gen.	3/stm. gen. in each operating stm. gen.	1, 2, 3	17

TABLE 3.3-2 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
6. Auxiliary Feedwater (Continued)					
2) Start Turbine-Driven Pump	4/stm. gen.	2/stm. gen. in any 2 operating stm. gen.	3/stm. gen. in each operating stm. gen.	1, 2, 3[d]	17
c. Safety Injection Start Motor-Driven Pumps	See Item 1. above for all Safety Injection initiating functions and requirements.				
d. Loss-of-Offsite Power Start Motor-Driven Pumps and Turbine-Driven Pump	1/train	1/train	1/train	1, 2, 3	16
e. Trip of All Main Feedwater Pumps Start Motor-Driven Pumps	2/AFW pump	2/AFW pump	1/AFW pump	1, 2	23
7. Automatic Initiation of ECCS Switchover to Containment Sump					
a. Automatic Actuation Logic and Actuation Relays	2	1	2	1, 2, 3, 4	~~12~~ 26

TABLE 3.3-2 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
7. Automatic Initiation of ECCS Switchover to Containment Sump (Continued)					
b. RWST Level--Low-Low	4	2	3	1, 2, 3, 4	~~26~~ 17
Coincident With: Safety Injection	See Item 1. above for all Safety Injection initiating functions and requirements.				
8. Loss of Power (6.9 kV & 480 V Safeguards System Undervoltage)					
a. 6.9 kV Preferred Offsite Source Undervoltage	2/bus	2/bus	1/bus	1†, 2†, 3†, 4†	23
b. 6.9 kV Alternate Offsite Source Undervoltage	2/bus	2/bus	1/bus	1, 2, 3, 4	23
c. 6.9 kV Bus Undervoltage	2/bus	2/bus	1/bus	1, 2, 3, 4	23
d. 6.9 kV Degraded Voltage	2/bus	2/bus	1/bus	1, 2, 3, 4	23
e. 480 V Degraded Voltage	2/bus	2/bus	1/bus	1, 2, 3, 4	23
f. 480 V Low Grid Undervoltage	2/bus	2/bus	1/bus	1, 2, 3, 4	23
9. Control Room Emergency Recirculation					
a. Manual Initiation	2	1	2	All	24

TABLE 3.3-2 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
b. Safety Injection	See Item 1. above for all Safety Injection initiating functions and requirements				
10. Engineered Safety Features Actuation System Interlocks					
a. Pressurizer Pressure, P-11	3	2	2	1, 2, 3	18
b. Reactor Trip, P-4	2	2	2	1, 2, 3	20
11. Solid State Safeguards Sequencer (SSSS)					
a. Safety Injection Sequence	1/train	1/train	1/train	1, 2, 3, 4	26
b. Blackout Sequence	1/train	1/train	1/train	1, 2, 3, 4	25

TABLE 3.3-2 (Continued)

TABLE NOTATIONS

[a]Trip function may be blocked in this MODE below the P-11 (Pressurizer Pressure Interlock) Setpoint.

[b]Trip function automatically blocked above P-11 and may be unblocked below P-11 by blocking the Safety Injection on low steam line pressure.

[c]Not applicable if each affected main steam isolation valve and its associated upstream drain pot isolation valve per steam line is closed.

[d]The provisions of Specification 4.0.4 are not applicable for entry into MODE 3.

[e]The channel which provides a steam generator water level control signal (if one of three specific trip channels is selected to provide input into steam generator water level control) must be placed in the tripped condition within 6 ~~1~~ hour and maintained in the tripped condition with the exception that the channel may be taken out of the tripped condition for up to ~~2~~ 4 hours to allow testing of redundant channels.

[f]Not applicable if Preferred Offsite Source Breaker is open.

ACTION STATEMENTS

ACTION 12 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, be in at least HOT STANDBY within 12 hours and in COLD SHUTDOWN within the following 30 hours; however, one channel may be bypassed for up to 2 hours for surveillance testing per Specification 4.3.2.1, provided the other channel is OPERABLE.

ACTION 13 - With the number of OPERABLE channels one less than the Total Number of Channels, operation may proceed until performance of the next required ANALOG CHANNEL OPERATIONAL TEST provided the inoperable channel is placed in the tripped condition within 1 hour.

ACTION 14 - With the number of OPERABLE channels one less than the Total Number of Channels, operation may proceed provided the inoperable channel is placed in the bypassed condition and the Minimum Channels OPERABLE requirement is met. One additional channel may be bypassed for up to 4 hours for surveillance testing per Specification 4.3.2.1.

ACTION 15 - With less than the Minimum Channels OPERABLE requirement, operation may continue provided the containment pressure relief valves are closed within 4 hours and maintained closed.

ACTION 16 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 48 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

TABLE 3.3-2 (Continued)

ACTION STATEMENTS (Continued)

ACTION 24 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 48 hours or initiate and maintain operation of the Control Room Emergency Recirculation System.

ACTION 25 - With the number of OPERABLE channels on one or more trains less than the Minimum Channels OPERABLE requirement, declare the diesel generator(s) associated with the affected train(s) inoperable and apply the appropriate ACTION for Specification 3.8.1.1.

ACTION 26 - With the number of OPERABLE channels one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed provided the following conditions are satisfied:

a. The inoperable channel is placed in a tripped condition within 6 hours, and

b. The Minimum Channels OPERABLE requirement is met; however, one additional channel may be bypassed for up to 2 hours for surveillance testing of other channels per Specification 4.3.2.1.

Action 26 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement restore the inoperable channel to OPERABLE status within 6 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours; however, one channel may be bypassed for up to 4 hours for surveillance testing per Specification 4.3.2.1, provided the other channel is OPERABLE.

TABLE 3.3-2 (Continued)

ACTION STATEMENTS (Continued)

ACTION 17 - With the number of OPERABLE channels one less than the Total Number of Channels, STARTUP and/or POWER ~~OPERATION~~ operation may proceed provided the following conditions are satisfied:

a. The inoperable channel is placed in the tripped condition within 6 hours, and

b. The Minimum Channels OPERABLE requirement is met; however, one additional channel may be bypassed for up to 4 hours for surveillance testing of other channels per Specification 4.3.2.1.

restore the inoperable channel to OPERABLE status within 6 hours or

ACTION 18 - With less than the Minimum Number of Channels OPERABLE, within 1 hour determine by observation of the associated permissive annunciator window(s) that the interlock is in its required state for the existing plant condition, or apply Specification 3.0.3.

ACTION 19 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, be in at least HOT STANDBY within the next 6 ~~12~~ hours and ~~in at least~~ HOT SHUTDOWN within the following 6 hours; however, one channel may be bypassed for up to ~~2~~ 4 hours for surveillance testing per Specification 4.3.2.1 provided the other channel is OPERABLE.

ACTION 20 - With the number of OPERABLE channels one less than the Total Number of Channels, restore the inoperable channel to OPERABLE status within 48 hours or be in at least HOT STANDBY within 6 hours and in at least HOT SHUTDOWN within the following 6 hours.

ACTION 21 - With the number of OPERABLE channels one less than the Total Number of Channels, restore the inoperable channel to OPERABLE status within 48 hours or declare the associated valve inoperable and take the ACTION required by Specification 3.7.1.5.

restore the inoperable channel to OPERABLE status within 6 hours or

ACTION 22 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, be in at least HOT STANDBY within the next 6 ~~12~~ hours; however, one channel may be bypassed for up to ~~2~~ 4 hours for surveillance testing per Specification 4.3.2.1 provided the other channel is OPERABLE.

ACTION 23 - With the number of OPERABLE channels one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed provided the following conditions are satisfied:

a. The inoperable channel is placed in the tripped condition within 6 hours, and

b. The Minimum Channels OPERABLE requirement is met.

TABLE 4.3-2 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

CHANNEL FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MASTER RELAY TEST	SLAVE RELAY TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
7. Automatic Initiation of ECCS Switchover to Containment Sump (Continued)								
b. RWST Level-Low-Low Coincident With	S	R	Q	N.A.	N.A.	N.A.	N.A.	1, 2, 3, 4
Safety Injection	See Item 1. above for all Safety Injection Surveillance Requirements.							
8. Loss of Power (6.9 kV & 480 V Safeguards System Undervoltage)								
a. 6.9 kV Preferred Offsite Source Undervoltage	N.A.	R	N.A.	(3, 2)	N.A.	N.A.	N.A.	1, 2, 3, 4
b. 6.9 kV Alternate Offsite Source Undervoltage	N.A.	R	N.A.	(3, 2)	N.A.	N.A.	N.A.	1, 2, 3, 4
c. 6.9 kV Bus Under-voltage	N.A.	R	N.A.	(3, 2)	N.A.	N.A.	N.A.	1, 2, 3, 4
d. 6.9 kV Degraded Voltage	N.A.	R	N.A.	(3, 2)	N.A.	N.A.	N.A.	1, 2, 3, 4
e. 480 V Degraded Voltage	N.A.	R	N.A.	(3, 2)	N.A.	N.A.	N.A.	1, 2, 3, 4
f. 480 V Low Grid Undervoltage	N.A.	R	N.A.	(3, 2)	N.A.	N.A.	N.A.	1, 2, 3, 4

TABLE 4.3-2 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

CHANNEL FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MASTER RELAY TEST	SLAVE RELAY TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
9. Control Room Emergency Recirculation								
a. Manual Initiation	N.A.	N.A.	N.A.	R	N.A.	N.A.	N.A.	All
b. Safety Injection	See Item 1. above for all Safety Injection Surveillance Requirements.							
10. Engineered Safety Features Actuation System Interlocks								
a. Pressurizer Pressure, P-11	N.A.	R	Q	N.A.	N.A.	N.A.	N.A.	1, 2, 3
b. Reactor Trip, P-4	N.A.	N.A.	N.A.	R	N.A.	N.A.	N.A.	1, 2, 3
11. Solid State Safeguards Sequencer (SSSS)								
a. Safety Injection Sequence	N.A.	R	N.A.	M(1,3,4)	N.A.	N.A.	N.A.	1, 2, 3, 4
b. Blackout Sequence	N.A.	R	N.A.	M(1,3,4)	N.A.	N.A.	N.A.	1, 2, 3, 4

3/4.3 INSTRUMENTATION

BASES

3/4.3.1 and 3/4.3.2 REACTOR TRIP SYSTEM and ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION

The OPERABILITY of the Reactor Trip System and the Engineered Safety Features Actuation System instrumentation and interlocks ensures that: (1) the associated ACTION and/or Reactor trip will be initiated when the parameter monitored by each channel or combination thereof reaches its Setpoint (2) the specified coincidence logic and sufficient redundancy is maintained to permit a channel to be out-of-service for testing or maintenance consistent with maintaining an appropriate level of reliability of the reactor protection and engineered safety features instrumentation, and (3) sufficient system functional capability is available from diverse parameters.

The OPERABILITY of these systems is required to provide the overall reliability, redundancy, and diversity assumed available in the facility design for the protection and mitigation of accident and transient conditions. The integrated operation of each of these systems is consistent with the assumptions used in the safety analyses. The Surveillance Requirements specified for these systems ensure that the overall system functional capability is maintained comparable to the original design standards. The periodic surveillance tests performed at the minimum frequencies are sufficient to demonstrate this capability. Specified surveillance intervals and surveillance and maintenance outage times have been determined in accordance with WCAP-10271, "Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System", and supplements to ~~that~~ those reports as approved by the NRC and documented in the SER (letters to ~~J. J. Sheppard from Cecil O. Thomas~~ the Westinghouse Owners Group (WOG) dated February 21, 1985,

, WCAP-10271 Supplement 2 "Evaluation of Surveillance Frequencies and Out of Service Times for the Engineered Safety Features Actuation System"

February 22, 1985 and April 30, 1990)

The Engineered Safety Features Actuation System Instrumentation Trip Setpoints specified in Table 3.3-3 are the nominal values at which the bistables are set for each functional unit. A Setpoint is considered to be adjusted consistent with the nominal value when the "as measured" Setpoint is within the band allowed for calibration accuracy.

To accommodate the instrument drift assumed to occur between operational tests and the accuracy to which Setpoints can be measured and calibrated, Allowable Values for the Setpoints have been specified in Table 3.3-3. Operation with Setpoints less conservative than the Trip Setpoint but within the Allowable Value is acceptable since an allowance has been made in the safety analysis to accommodate this error. An optional provision has been included for determining the OPERABILITY of a channel when its Trip Setpoint is found to exceed the Allowable Value. The methodology of this option utilizes the "as measured" deviation from the specified calibration point for rack and sensor components in conjunction with a statistical combination of the other uncertainties of the instrumentation to measure the process variable and the uncertainties in calibrating the instrumentation. In Equation 2.2-1, $Z + R + S \leq TA$, the interactive effects of the errors in the rack and the sensor, and the "as measured" values of the errors are considered. Z, as specified in Table 3.3-3, in percent span, is the statistical summation of errors assumed in the analysis excluding those associated with the sensor and rack drift and the accuracy of their measurement. TA or Total Allowance is the difference, in percent span, R or Rack Error is the "as measured" deviation, in the percent span, for the affected channel from the specified Trip Setpoint. S or Sensor Error is either the "as measured" deviation of

INSTRUMENTATION

BASES

REACTOR TRIP SYSTEM and ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION (Continued)

the sensor from its calibration point or the value specified in Table 3.3-3, in percent span, from the analysis assumptions. Use of Equation 2.2-1 allows for a sensor drift factor, an increased rack drift factor, and provides a threshold value for REPORTABLE EVENTS.

The methodology to derive the Trip Setpoints is based upon combining all of the uncertainties in the channels. Inherent to the determination of the Trip Setpoints are the magnitudes of these channel uncertainties. Sensor and rack instrumentation utilized in these channels are expected to be capable of operating within the allowances of these uncertainty magnitudes. Rack drift in excess of the Allowable Value exhibits the behavior that the rack has not met its allowance. Being that there is a small statistical chance that this will happen, an infrequent excessive drift is expected. Rack or sensor drift, in excess of the allowance that is more than occasional, may be indicative of more serious problems and should warrant further investigation.

The measurement of response time specified in the Technical Requirements Manual at the specified frequencies provides assurance that the Reactor trip and the Engineered Safety Features actuation associated with each channel is completed within the time limit assumed in the safety analyses. No credit was taken in the analyses for those channels with response times indicated as not applicable. Response time may be demonstrated by any series of sequential, overlapping, or total channel test measurements provided that such tests demonstrate the total channel response time as defined. Sensor response time verification may be demonstrated by either: (1) in place, onsite, or offsite test measurements, or (2) utilizing replacement sensors with certified response time.

The Engineered Safety Features Actuation System senses selected plant parameters and determines whether or not predetermined limits are being exceeded. If they are, the signals are combined into logic matrices sensitive to combinations indicative of various accidents events, and transients. Once the required logic combination is completed, the system sends actuation signals to those Engineered Safety Features components whose aggregate function best serves the requirements of the condition. As an example, the following actions may be initiated by the Engineered Safety Features Actuation System to mitigate the consequences of a steam line break or loss-of-coolant accident: (1) ECCS pumps start and automatic valves position, (2) Reactor trip, (3) feedwater isolation, (4) startup of the emergency diesel generators, (5) containment spray pumps start and automatic valves position (6) containment isolation, (7) steam line isolation, (8) turbine trip, (9) auxiliary feedwater pumps start and automatic valves position, (10) station service water pumps start and automatic valves position, (11) Control Room Emergency Recirculation starts, and (12) essential ventilation systems (safety chilled water, electrical area fans, primary plant ventilation ESF exhaust fans, battery room exhaust fans, and UPS ventilation) start.