CEOG COMBUSTION ENGINEERING OWNERS GROUP

CEN-403

ESFAS SUBGROUP RELAY

TEST INTERVAL EXTENSION

PREPARED FOR THE

C-E OWNERS GROUP

JULY, 1991

ABB COMBUSTION ENGINEERING

NUCLEAR POWER

COMBUSTION ENGINEERING, INC.

LEGAL NOTICE

EXECUTIVE SUMMARY

This report was prepared to justify extending the ESFAS subgroup relay surveillance test interval (STI) for Combustion Engineering (CE) plants. The report was prepared by CE on behalf of the Combustion Engineering Owners Group (CEOG).

Based on the findings of this study the surveillance interval for these relays can be extended for all CE plants that do not currently have an 18 month testing interval. Current STIs range from monthly to every refueling, depending on the plant. The proposed change to the STI is based on the over-testing of other plant equipment as a result of this test, and the reliability of these relays.

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1.0 PURPOSE

This report was prepared to justify extending the Surveillance Test Interval (STI) for Engineered Safety Features Actuation System (ESFAS) subgroup relays used in Combustion Engineering (CE) plants.

2.0 BACKGROUND

A semi-annual test frequency for subgroup relays first appeared in the draft Revision 3 to the CE Standard Technical Specifications (STS) (1) in 1982. The NRC Committee to Review Generic Requirements (CRGR) spent two years considering this set of STS. This draft STS was not approved, and has remained the basis for the semi-annual frequency.

In parallel with the CRGR discussions on the draft Revision 3 to the CE STS, Southern California Edison (SCE) was licensing their first CE unit, San Onofre (SONGS) Unit 2. During the SONGS licensing process, SCE presented arguments for a refueling (18 month) test frequency. These arguments were based on the reliability of the subgroup relays and the cost in having to shut down the plant to test some of them. A plant shutdown is required to test the subgroup relays which actuate equipment that cannot be tested at power. Subsequently SCE was granted a license with an 18 month test frequency for those relays that could not be tested at power, and a 6 month test frequency for relays that could be tested at power.

Florida Power and Light Company (FPL) submitted an amendment (2) to the St. Lucie Unit 2 (SL2) operating license to modify the subgroup relay test frequency in May 1984. This amendment utilized a probabilistic analysis to justify an increase in the test interval from 6 months to 18 months. This request was denied (3) based on an evaluation of the FPL analysis performed by EG&G for the NRC. The FPL analysis showed an insignificant (0.03%) decrease in availability due to the proposed increase in test interval. However, the EG&G analysis found an order of magnitude increase in unavailability between the two test intervals, which formed the basis for the NRC's rejection of the FPL amendment

request. At an availability of better than .998 for ESFAS systems, these two results are consistent with each other, and merely expressed in different forms. As such, the decreased availability, which is to be expected from an increased test interval, is not of so great a magnitude as to justify rejection of the amendment request.

As early as 1983, the Nuclear Regulatory Commission (NRC) recognized the burden imposed by excessive technical specification surveillance requirements. The NRC staff has evaluated how the technical specifications can be modified or restructured to reduce the burden on the nuclear power plants and improve reliability without adversely affecting the health and safety of the public. The results of this evaluation are reported in NUREG 1024 (4).

This evaluation resulted in establishment of the Technical Specification Improvement Program (TSIP) in December of 1984 by Harold Denton, Director of the NRC's Office of Nuclear Reactor Regulation (NRR). This effort has led to a complete rewriting and streamlining of technical specifications, as well as the development of specific line item improvements. As part of this effort the Combustion Engineering Owners Group (CEOG) submitted topical reports proposing changes to surveillance test intervals and allowed outage times on the Reactor Protection System (RPS) and ESFAS.

Related to RPS and ESFAS testing, CEN-327 "<u>RPS/ESFAS Extended Test Interval Evaluation</u>" (5), justified extension of the surveillance intervals for the RPS and ESFAS functional tests to 90 days. The NRC evaluation of CEN-327 is presented in Reference 6. CEN-327 was approved by the NRC in November 1989. Subsequently, CEOG Task 620 (7) was approved by the CEOG to justify an extension of the test frequency to 120 days on a staggered test basis (one channel every 30 days).

Extension of the test interval for the subgroup relays actuating the ESFAS components was specifically excluded from the CEN-327 effort. Including the subgroup relays would require a different generic grouping of the plants. To evaluate the different generic grouping, given the

large number of subgroup relays would require a very large and plant specific PRA.

As an outcome of the TSIP, the NRC staff performed a comprehensive study of technical specifications surveillance requirements, as recommended in NUREG 1024. The results of this study are contained in NUREG 1366 (8). Individual types of components, their failure history and the consequences of testing were examined in establishing NUREG 1366. This examination was based on three of five recommendations stated in NUREG 1024. These three recommendations are as follows:

Recommendation 1:	The testing frequencies in the technical specifications should be reviewed to assure that they are adequately supported on a technical basis and that risk to the public is minimized.
Recommendation 2:	The required surveillance tests should be reviewed to assure safety equipment is not degraded as a result of testing and that such tests are conducted in a safe manner and in the appropriate plant operational mode to ensure that risk to the public is minimized.
Recommendation 4:	The surveillance test requirements should be reviewed to assure that they do not consume plant personnel time unnecessarily or result in undue radiation exposure to plant personnel without a commensurate safety benefit in terms of minimizing public risk.

These three recommendations led to the four criteria (discussed below) in NUREG 1366. The NRC used these four criteria to determine if a surveillance test interval could be changed.

° Criteria 1 - The surveillance could lead to a plant transient,

- Criteria 2 - The surveillance results in unnecessary wear to equipment,

- Criteria 3 - The surveillance results in radiation exposure to plant personnel which is not justified by the safety significance of the surveillance.

- Criteria 4 - The surveillance places an unnecessary burden on plant personnel because the time required is not justified by the safety significance of the surveillance.

These four criteria will be compared with the criteria established in this study, in Section 4.0

Section 5.2 of NUREG 1366 addresses ESFAS slave relay testing. The term "slave relay" is more commonly known as "auxiliary relay" or "subgroup relay" at CEOG member plants. The term "subgroup relay" in this report refers to the "slave relays" of Section 5.2 of NUREG 1366.

NUREG 1366 outlined two findings: 1) subgroup relay reliability is generally good, 2) testing at power contributes to the frequency of inadvertent equipment starts and reactor trips. Equipment reliability was not one of the four criteria originally set forth in NUREG 1366, but was suggested as a basis for relaxation.

2.1 CURRENT SURVEILLANCE TEST INTERVALS

Although some subgroup relays are not testable at power and thus have an 18-month test frequency, those that are testable at power have shorter surveillance intervals as listed in Table 1. Table 1 summarizes information on the testing, failure history, surveillance test intervals, number of relays and manufacturers of the subgroup relays used at CE plants. Several plants have surveillance intervals of once per quarter or longer while a number of plants have a more restrictive monthly test interval. As there does not appear to be a technical basis for this short surveillance interval, it is believed these surveillance

intervals are candidates for extension.

The current surveillance test intervals are believed to originally have been based on engineering judgement. Differences between the CE Standard Technical Specifications (STS) (1) and individual plant surveillance frequencies generally have not been based on the mean time between failures or a reliability study. Now that plants have a sufficient operating history on these relays a more accurate test interval can be technically justified.

The individual plant failure history is more dependant on the relay manufacturer and environment than the test interval. This will be further demonstrated in Section 4.0 (Discussions) of this report. Now that an operating and failure history of these relays is established, more accurate surveillance frequencies can be technically justified.

TABLE 1

RELAY INFORMATION SUMMARY

PLANT	CE DESIGNED ESFAS	RELAY MFR	PB NEW%	FAILURES NP	FAILURES MR	SURVEILLANCE INTERVAL	NOTES
ARKANSAS UNIT 2	Y	PB	N/R	8	N/A	18 months	
CALVERT CLIFFS 1	N	Genicom	N/A	1	N/A	Monthly	Formerly General Electric
CALVERT CLIFFS 2	N	Genicom	N/A	0	N/A	Monthly	Formerly General Electric
FORT CALHOUN	N	GE	N/A	9	N/A	Monthly	Normally Deenergized
MAINE YANKEE	N	Numerous	N/A	N/A	N/A	Refueling	Portions (ND & NE) (not part of study)
MILLSTONE 2	N	Deutsch	N/A	0	1	Monthly	
PALISADES	N	N/A	N/A	N/A	N/A	Quarterly	Normally Deenergized (not part of study)
PALO VERDE 1	Y	PB	100	3	)	62 Days	No failures on new relays
PALO VERDE 2	Y	PB	100	8	)15**	62 Days	" "
PALO VERDE 3	Y	PB	100	3	)	62 Days	" "
SAN ONOFRE 2	Y	PB	100	5	0	Semi-annually	" "
SAN ONOFRE 3	Y	PB	100	2	0	Semi-annually	" "
ST. LUCIE 1	N	Couch	N/A	2	3	18 months	
ST. LUCIE 2	N	Couch	N/A	1	2	Semi-annually	
WATERFORD 3	Y	PB	N/R	1	1	62 Days	

The following notes are given to explain Table 1.

° Column labeled "PB NEW%", is the percentage of newer model Potter Brumfield relays (Section 2.3.1) a plant currently has. "N/R" stands for "no records", or the information is not known. "N/A" is used when a plant does not have Potter Brumfield relays.

° Column labeled "Failures" Represents the number of failures found through the INPO Nuclear Plant Reliability Database System (NPRDS) and through plant maintenance records. The "NP" sub-column represents the number of failures found through the NPRDS system. The "MR" sub-column represents the number of failures that maintenance personnel at the respective sites reported. In this sub-column N/A represents records were not available.

** Two stars (**) next to Palo Verde is used because an LER showed a greater number of failures than the NPRDS database. However, all the failures reported in Table 1 are on the original model of relay. This original relay model has been completely replaced. There have been no reported failures on the new relays.

° Column labeled "Surveillance Interval" shows the current subject surveillance frequency.

Acronyms; ND = Normally Deenergized ESFAS system.
NE = Normally Energized ESFAS system

In Table 1, certain assumptions were made. For Millstone Unit 2 and Saint Lucie Units 1 and 2, discussions with plant personnel suggested a higher number of failures than what was found in the NPRDS system. These three plants are older and failures may have occurred before the NPRDS system was in full use. The conservative number was used in the analysis. Palo Verde Units 1, 2, 3 and San Onofre Units 2 and 3, replaced all their relays with an upgraded model. Therefore, the number of failures on the new model relay and corresponding years of reactor operation on these new model relays were used for the calculations presented in Tables 3 and 4. The failure rate of the old relays would have given inaccurate data. Maine Yankee has numerous manufacturers of relays. Discussions with plant personnel suggested a small number of failures. Maine Yankee has a preventative maintenance program for these relays, therefore, some of these relays are replaced on a periodic

relays, therefore, some of these relays are replaced on a periodic basis. Failure data for Maine Yankee was not included in this study. Palisades has a different arrangement for their ESFAS system than that used in other plants. Palisades does not have "subgroup relays" as used in other plants. Therefore, failure data for Palisades was not included in this study.

2.2 ESFAS DESCRIPTION

The primary purpose of the EFSAS is to initiate automatic operation of certain plant equipment. This equipment aids in mitigating and terminating Design Basis Accidents (DBAs) in order to protect the health and safety of the public.

The following descriptions are of a generic nature only, since there is large diversity between the ESFAS at CE plants.

The ESFAS consists of four sensor subsystems and two actuation subsystems. The actuation subsystems may include a logic subsystem for sequentially loading the diesel generators.

<u>Sensor Subsystem</u>

Each independent sensor monitors a process parameter. The four sensors actuate independently when the monitored variables reach predetermined levels. Typical process parameters:

° Containment pressure
° Pressurizer pressure
° Refueling water tank level
° Steam generator pressure
° Steam generator level

Four Initiation Relay Contacts (IRC) are opened (two per leg) when any two out of four sensor relays sense a process parameter beyond the setpoint.

Actuation Subsystem

This study is primarily concerned with the actuation subsystem. The two redundant and independent actuation subsystems monitor the sensor channel trip outputs and, by means of a coincidence logic, determine whether protective action is required. Each actuation subsystem initiates equipment (protective systems). Each channel controls sufficient equipment to ensure protection of the public health and safety in the event of a DBA.

Specific sensor and actuation channels are arranged to produce signals which initiate equipment operation consistent with the type of protective action required.

The actuation channels of the Safety Injection Actuation System (SIAS), Containment Spray Actuation System (CSAS), Containment Isolation Actuation System (CIAS) and bus under voltage signal are subdivided into multiple parts. This subdivision allows convenient and flexible periodic testing. In addition it reduces the amount of equipment actuated by a single relay.

The ESFAS at plants with a CE supplied Nuclear Steam Supply System (NSSS) can be divided into two classes based on source of ESFAS design, they are:

- Plants that utilize an ESFAS designed by CE, and
- Plants that utilize a non-CE ESFAS design.

Plants with CE designed ESFAS are generally newer. They are designated digital because they have Core Protection Calculators (CPCs). CPCs use computer programs to calculate and generate certain reactor trips.

Plants with non-CE designed ESFAS are generally older. These plants lack CPCs. These plants are designated "analog" because they use analog signals and mathematical modules to calculate reactor trip setpoints. A variety of vendors designed and built the analog ESFAS cabinets.

How one interprets the definition of analog and digital may vary depending on ones technical discipline (engineer, I&C technician, operations personnel, etc.) however, in this report the distinction is based on the presence or lack of CPCs.

The CE ESFAS design is utilized at Waterford Unit 3, Arkansas One Unit 2, San Onofre Units 2 and 3, and Palo Verde Units 1, 2 and 3. The plants utilizing a non-CE ESFAS design are Palisades, Fort Calhoun, Millstone Unit 2, Calvert Cliffs 1 and 2, St. Lucie 1 and 2 and Maine Yankee.

The CE ESFAS design is standard among the plants utilizing it. The non-CE ESFAS have been built by a variety of vendors, and as such they are unique in design and operation. The plant specific FSARs should be referred to for a complete description of the ESFAS system.

2.3 SUBGROUP RELAY DESCRIPTION

As shown in Figure 1, subgroup relays are the last relays in the circuit before the actuated equipment. As such, upon de-energization,[1] they initiate the proper signal to supply power in order to actuate the various pump, valve, etc. controllers.

Figure 1 shows a typical ESFAS cabinet schematic for one signal, e.g. SIAS. When the monitored parameters reach the predetermined level it will open the ESFAS initiation relay contacts.

The number of subgroup relays per plant varies. The analog plants typically have approximately 100 subgroup relays per ESFAS cabinet. There are two cabinets for a total of approximately 200 subgroup relays. The digital plants typically have between 106 and 112 relays total. This number will vary because there were usually "spare" locations provided for addition of more subgroup relays as the plant needs. Plants may or may not be using these "spare" locations depending in part

[1] Some plants are energized to actuate, Refer to Table 1

on the design upgrades they have incorporated.

The subgroup relays are actuation relays and not initiation relays. "actuation" and "initiation" are uses of relays.

2.3.1 RELAY MANUFACTURERS

The five manufacturers of subgroup relays used in CE plants are Potter Brumfield, General Electric, Genicom (formerly General Electric), Deutsch, and Thomas A. Couch (a division of ESB). The following sections discuss the relay types provided by each manufacturer.

Potter Brumfield

Potter Brumfield (PB) MDR Series 7032, 7033, 7034 and 136-1 rotary relays, (commercially available items) are used at all plants with a CE designed ESFAS.[2] MDR series 7032, 7033 and 7034 comprise the majority of relays used. These are used in all non-cycling applications (or all except for AFW). Series 136-1 relays are cycling relays typically used for AFW.

The basic construction of these relays consists of a rotary actuator mechanism with contact sections mounted in isolated rings. They are non-latching and are normally energized in the non-actuated position during operation (as opposed to "latching" relays which hold their position once energized to actuate). These relays fail in the actuated position on a loss of dc control power.

In the past, there were many failures of the PB relays. These failures have been associated with the heat generated by being continuously energized, or by over-voltage being applied. These relays are 24 V-dc devices (operated at an increased voltage of 36 V-dc, because of downstream voltage losses, to assure that minimum voltage is maintained).

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[2] Refer to Table 1

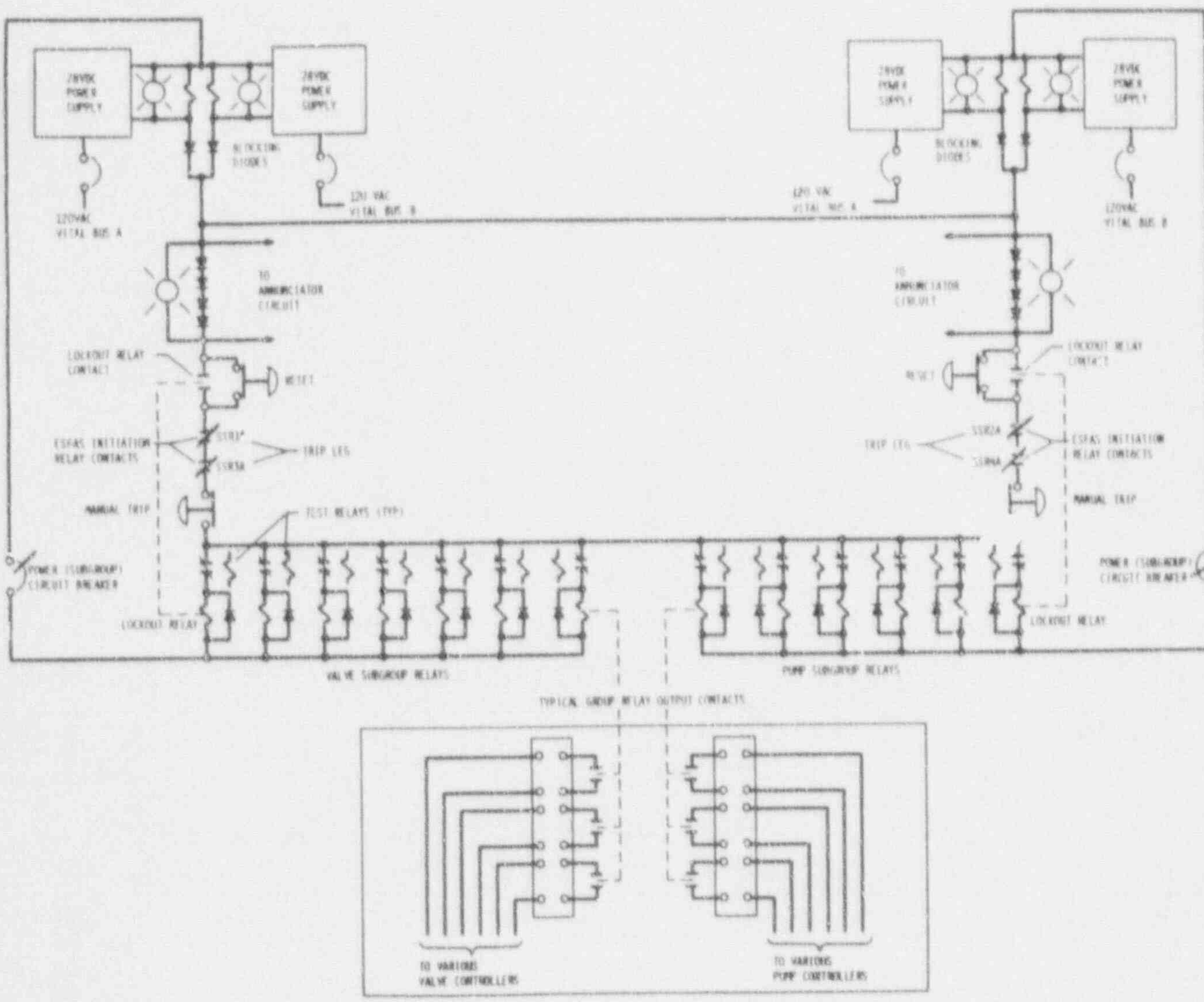
FIGURE 1

DIGITAL ESFAS AUXILIARY RELAY CABINET SIMPLIFIED SCHEMATIC

TYPICAL ACTUATION SIGNAL IN 1 TRAIN

(shown energized)

reset



To investigate this problem, Arizona Nuclear Power Projects (ANPP), operator of Palo Verde Units 1, 2 and 3 contracted two laboratories, Scanning Electron Analysis Laboratories, Inc. (SEAL) and HI REL. The labs determined a majority of the failures could be attributed to excessive heat and degassing of the varnish coating. Contaminants would plate out or corrosion would occur on the internal motor surfaces causing the relays to stick in the (open) position. The corrosion buildup prevented full rotor movement and thereby prevented the contacts from changing state and actuating the associated equipment.

The problems identified were resolved by the manufacturer and ANPP with the development of a new style of relay. This new style of relay has an epoxy resin coating instead of varnish, some brass components were replaced with stainless steel and other material changes were made (9). The newer model initially had problems caused by an improperly cured coating on a batch of the relays. This problem is also believed to be solved.

Palo Verde Units 1, 2 and 3 and San Onofre Units 1 and 2 have completely replaced the older model Potter Brumfield relays with the newer model. The newer model of relay has proven to have an excellent operating history, with no reported failures since their installation.[3]

The older style relays used at Arkansas Unit 2 and Waterford 3 are not subjected to the same environmental conditions as those at Palo Verde. The majority (6 out of 9) of the failures at Arkansas Unit 2 and Waterford 3 were attributed to normal wear and dirt buildup. The other three failures were attributed to unknown reasons. Although it is possible for these relays to fail in the "open" position, in all nine failures the relay failed with the contacts in the closed position. When this happens, the relay remains energized, resulting in the equipment associated with the relay failing to actuate.

Carolina Power & Light's (CP&L's) Shearon Harris nuclear plant received

[3] Refer to Table 1

a shipment of refurbished PB relays. These refurbished relays were found to be materially and functionally substandard. The Discrepancies were identified prior to installation , through receipt inspection and testing at the PB factory. This occurrence, was addressed in NRC Information Notice 90-057, (10).

General Electric

General Electric (GE) series HFA, CR120 or HAG relays are used at Fort Calhoun Station.

Series CR120 relays are generally two and four pole, which may contain two or four pole adders, to give a maximum of twelve poles. These relays generally have self cleaning contacts.

The failure rate on these relays is higher than the other relays used at CEOG plants.[4] In three of the nine failures of these relays the relay failed to energize, thereby not actuating the associated equipment. In four of the failures the relay energized but the contacts did not open, usually causing the relay to burn out. These failures resulted in the equipment failing to actuate. Of the two remaining failures one relay did not operate within time limits and the other relay did not fail but made excessive noise indicating possible failure.

Genicom

Genicom (formerly General Electric) series 3SAA1383A2 relays are used at Calvert Cliffs Units 1 and 2. Information concerning these relays (including NPRDS information) is usually found under GE. The relays have an excellent operating history, therefore there is a limited number of reports on them in NPRDS database. An option for searching on the manufacturers name is not included in the NPRDS database.

[4] Refer to Table 1.

The Genicom relays used at Calvert Cliffs are miniature, canned, plug-in, 25V DC relays.

There is one reported failure of these relays. The relay failed due to cyclic fatigue and resulted in the failure of a CCW pump to start.

Deutsch

Deutsch Series ZAP-X1596 relays are used at Millstone Unit 2. There was no information available on the failure modes of these relays in the NPRDS system.

Thomas A. Couch

Couch (a division of ESB) model number KEN 431A, Part number 4CP AF relays are used at St. Lucie Units 1 and 2. Out of the three failures for which information is available, two relays failed to open; no reason was given for the third failure. The first failure resulted in a CCW valve failing to actuate. The second failure resulted in a false SIAS closing two valves. This resulted in a loss of the "B" train for the two valves.

2.3.2 RELAY OPERATION

During normal operation, the ESFAS Initiation Relay Contacts (IRC) (Figure 1) are normally closed. When the two power (subgroup) circuit breakers are closed and the lockout relay contact reset is depressed, the subgroup relays and lockout relays become energized. The trip legs for the auxiliary relay cabinet are then operative and are ready to respond to an initiation signal. Upon receipt of proper initiation "two-out-of-four" signals, the IRC contacts de-energize opening both trip legs. This causes the subgroup relays to become de-energized. The contacts on these relays then actuate various valve and pump controllers.

As a result of the trip, each de-energized lockout relay opens a set of

contacts in series with the IRCs. This arrangement prevents the trip legs from inadvertently reenergizing until the operator manually resets the lockout relay. Pressing either Lockout Reset button energizes the lockout and subgroup relays in both trip legs.

There is a pair of trip legs similar to the ones shown on Figure 1 for each subgroup function, e.g., SIAS. During normal operation, all of these trip legs are operative and ready to respond to their separate set of two-out-of-four signals that the PPS supplies.

2.3.3 RELAY TESTING

Note: for the purposes of this report, it is assumed that in order for a subgroup relay to meet a surveillance requirement all components connected to it must actuate when the relay is de-energized.[5] The testing sequence described below is of a generic nature, plant surveillance procedures and technical manuals should be consulted for plant specific testing methods.

The subgroup relays are tested using a remote test module. Generally, several rotary switches are mounted on the front panel of the test module. These switches provide for selection of any particular subgroup relay for testing.

Once the desired subgroup relay is chosen and the initiate action button is depressed, the test relay contacts will open, de-energizing[6] the subgroup relay. This in turn actuates the ESFAS equipment. A list of typical equipment (one train) actuated as a result of this test is summarized in Table 2.

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[5] Some applications are energized to actuate, Refer to Table 1.

[6] Some applications are energized to actuate, Refer to Table 1.

TABLE 2

LIST OF TYPICALLY ACTUATED EQUIPMENT

Actuation Subsystem	Action
1) SIAS	Starts SWS air compressors Starts HPSI pumps Starts LPSI pumps Starts component cooling pumps Starts SRW pumps Starts salt water pumps Starts diesel generator(s) Closes cntmnt hot water heat isolation valve Closes cntmnt waste gas header vent valve Closes RC loop hot leg sample valve Closes SI tank bleedoff valve Closes RC sample containment isolation valve Closes SI loop leakage check valves Closes VCT makeup flow valve Closes turbine building SRW isolation valve Closes turb lube oil & EHC oil clr isol vlv Closes RCP seals bleedoff cntmnt isol valves Closes VCT discharge valves Closes letdown line cntmnt isolation valves Closes comp cooling HX salt water inlet valve Closes comp cooling HX salt water outlet valves Closes circ water pump room air cooler salt water isolation valves Closes diesel generator feeder breaker Closes cntmnt normal sump drain isolation valve Closes cntmnt purge air supply isolation valve Closes cntmnt purge air exhaust isolation valve Closes cntmnt waste gas header vent valve Closes cntmnt normal sump drain isolation valve Closes cntmnt purge air supply isolation valve Closes cntmnt purge air exhaust isolation valve Closes cntmnt purge air sampling isolation valve Closes pressurizer vapor sampling valve Closes pressurizer liquid sampling valves Closes RCDT pump discharge cntmnt isol valve Closes pzr quench tank oxygen sample valve Closes hydrogen purge exhaust valves Opens containment spray header isolation valves Opens HPSI valves Opens HPSI redundant header valves Opens Auxiliary HPSI valves Opens LPSI valves Opens BAST gravity valve

Table 2 (continued)

3) SIAS (continued)	
	Opens BAST recirc valves
	Opens BA pump makeup bypass valve
	Opens pressurizer backup heater breakers
	Opens comp cooling S/D cooling HX outlet valves
	Opens SRW HX salt water outlet valve
	Stops cntmnt purge air sampling isolation valve
	Stops cntmnt purge air exhaust fan
	Stops cntmnt purge air supply fan
2) CSAS	Starts containment coolers
	Closes containment cooler SRW outlet valves
	Closes Spent Fuel Pool cooler SRW outlet valves
	Closes containment spray pumps
	Closes Feedwater isolation valves
	Closes Main steam isolation valves
	Trips Heater drain pumps
	Trips Main feedwater pumps
	Trips Condensate booster pumps
3) CIS	Starts containment charcoal filter unit
	Starts penetration room exhaust fans
	De-energizes penetration room filters
	Closes instrument air cntmnt isolation valve
	Closes RCP comp cooling cntmnt isolation valve
	Closes liquid waste evaporator
4) CRS	Closes cntmnt purge air supply isol valves
	Closes cntmnt purge air exhaust isol valves
	Closes hydrogen purge exhaust valves
	Stops cntmnt purge air exhaust fans
5) RAS	Returns to auto component cooling HX
	Returns to auto SRW HX
	Opens component cooling water HX
	Opens cntmnt sump discharge valve
	Closes CS & SI pumps recirc valves
	Stops LPSI pumps
5) SGIS	Closes SG isolation valves
	Closes MSIV
	Trips Heater drain pumps
	Trips Main feedwater pumps
	Trips Condensate booster pumps

The relay-component alignments are very plant specific. In general pieces of equipment that can not be tested together at power will not be grouped on the same subgroup relay (for example, a Low Pressure Safety Injection (LPSI) pump and a LPSI discharge valve could result in inadvertent flow to the core). Most components can be actuated together as long as they are not part of the same ESFAS function. If two components (for example a High Pressure Safety Injection (HPSI) pump and a HPSI discharge isolation valve) are actuated from the same relay and can not be tested concurrently, then the relay testing is usually performed in two steps. One piece of equipment is blocked (possibly by opening or racking out its breaker) and then the relay is de-energized. Then, the lineup is reversed. This verifies all the contacts on the relay are tested. These tests reqire time for planning, installation and removal of blocking and increases the chance of causing inadvertent equipment operation, damage or personal injury.

Plants may actuate the subgroup relays along with other required tests, such as;

- Bleedoff Isolation Valves
- Service Water Isolation Valves
- Volume Control Tank (VCT) Discharge Valves
- Letdown Stop Valves
- Component Cooling Water (CCW) to Reactor Coolant Pump (RCP)
- CCW from RCP
- Main Steam Isolation Valves and MFIVs
- Service Water Isolation Valves
- Volume Control Tank (VCT) Discharge Valves
- Letdown Stop Valves
- Component Cooling Water (CCW) to Reactor Coolant Pump (RCP)
- CCW from RCP
- Main Steam Isolation Valves and MFIVs
- Instrument Air Containment Isolation Valves.

These cannot be tested at power for obvious reasons.

The subject surveillance test in the CE-STS SR 4.3.2.1 (1), is referred to as a Channel Functional Test and reads;

> "4.3.2.1 Each ESFAS instrumentation channel shall be demonstrated operable by the performance of the CHANNEL CHECK, CHANNEL CALIBRATION, and CHANNEL FUNCTIONAL TEST operations for the MODES and at the frequencies shown in Table 4.3-2".

Table 4.3-2 of the CE STS lists the individual functional units separating the automatic actuation logic, manual trips, and measured parameters. The automatic actuation logic has a note stating:

> "A subgroup relay test shall be performed which shall include the energization/de-energization of each subgroup relay and verification of the OPERABILITY of each subgroup relay."
> semiannual frequency is given for each functional unit.

3.0 FAILURE DISCUSSION

This section discusses the relay failure modes, how the failures were discovered and the consequences of failure. Failure data was collected and analyzed for all CE plants through use of the INPO NPRDS, plant maintenance records and contact with plant personnel.[7]

Out of the 25 relay failures in Table 1, the failure causes can be broken down as follows; seven failures were attributed to normal wear/aging five failures were from dirt or corrosion, one failure was from mechanical binding and the remaining 12 failures were not attributed to any one particular reason (in the NPRDS information).

The seven relays that failed due to normal wear/aging and the relay that failed due to mechanical binding were replaced. Out of the five relays that failed due to dirt or corrosion, three were cleaned/retested and returned to service, the remaining two were replaced.

Relays generally fail in either an actuated position or an as-is position. If a relay fails in the actuated position the ESFAS equipment will start, thereby alerting the operator to the failure. This is a conservative failure. If the relay fails as is, the ESFAS equipment will not actuate, either as a result of the failure or upon demand. The operator will not be aware of the non-conservative failure until the relay is tested or a demand is made for ESFAS equipment operation.

Out of the 25 relay failures in this study, approximately half failed conservatively (spurious energization of a de-energized relay or spurious de-energization of an energized relay) and half failed non-conservatively. All failures were counted in this study. In two instances relays had delayed actuation, in these cases they failed in the conservative position.

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[7] Except as noted in Table 1

All the relay failures were discovered through one of five means; surveillance testing, routine observation, maintenance, random and unknown (a reason was not given). Surveillance testing revealed 13 failures routine observation revealed two failures, maintenance revealed three failures, five were discovered randomly, and information is not available on the other two failures.

Note the data in this report is based on thirteen plants. Data for Palisades and Maine Yankee was not available. Palisades has a somewhat unique, older ESFAS system which does not utilize typical subgroup relays. Maine Yankee uses numerous manufacturers for their subgroup relays.

4.0 DISCUSSION

This section discusses relay reliability, the establishment of criteria for determining an acceptable test interval and application of the criteria.

4.1 RELIABILITY

The reliability of the subject relays was studied by two methods. The first method discusses the "general" findings. The second method is a formalized Probabilistic Risk Analysis (PRA) approach. Both methods are discussed below.

As of January 1, 1991, 103 "Time in service years[8]" of operation have been experienced by the 13 CE plants with the current relay configuration. During this period there have been 25 reported subgroup relay failures[9]. This gives a frequency of 0.24 (25/103) events per reactor year (ev/ry). Alternatively, this gives an average number of 1.92 (25/13) failures per plant.

Out of the 25 total failures, 17 (over 60%) occurred at two plants, Fort Calhoun and Arkansas Unit 2. Although Arkansas Unit 2 has had eight failures the mean life of the relays at Arkansas is approximately 120 months (10 years). The eight relays that have failed were in service a mean of 6.5 years at the time of failure. At Fort Calhoun, the mean life of their relays (General Electric) is 189 months (15.8) years. The nine failed relays were in service at Fort Calhoun a mean of 165 months (13.7 years) at the time of failure.

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[8] the cumulative number of years the current model relay has been in service

[9] Excluding failures on relays no longer in use, Table 1

If the same analysis is applied to all thirteen plants, as applied to Fort Calhoun and Arkansas the following data is obtained;

- Mean relay life of all relays 9.38 years (112.5 months).
- Mean life of failed relay 10.94 years (131.28 months).
- Mean time between failures 23 months (average per CE plant).

The mean lifetime of the failed relays is larger than the mean lifetime of "all the relays" because some plants have been operating for a very short time consequently having reduced calculated mean lifetime.

The remaining 11 CE plants (besides Fort Calhoun and Arkansas) have had fewer than five relay failures each. Therefore, if analyzed individually, these plants would have more conservative numbers then presented above.

Maine Yankee is the only plant having a preventative maintenance program for these relays, and therefore was excluded from this study. The above calculations for the remaining 11 plants assume the original relays are in service unless they have failed.

A more formalized approach (PRA) to studying the relay reliability did not provide conclusive results due to limited sample size. However, as a result of this PRA, Tables 3 and 4 were generated. Tables 3 and 4 are derived from the failure information summarized in Table 1. The test results were analyzed both individually and grouped by test interval. Table 3 presents information on the relay reliability based on observed tests, summarizes the number of relays and the number of tests per plant. Table 4, relay test results binned by test interval, correspond the number of tests with the number of failures by the test interval.

TABLE 3

RELAY RELIABILITY BASED ON OBSERVED TESTS

PLANT	TIME IN SERVICE YEARS	NO. OF RELAYS	NO. OF FAILURES	NO. OF TESTS
CC1	15.58	200	1	37,392
CC2	13.67	200	0	32,808
Ft Cal.	16.5	200	9	39,600
Milst 2	15.0	200	1	36,000
Watfd 3	5.25	109	1	3,434
PV 1	0.75*	114	0	513
PV 2	0.83*	114	0	570
PV 3	1.0*	109	0	684
SONGS 2	1.17*	109	0	254
SONGS 3	0.75*	109	0	163
St Lucie 2	7.75	200	2	3,100
St Lucie 1	14.0	200	3	1,876
ANO 2	10.75	109	8	785
	103		25	~157,000

* For these plants, the number of years stated is different than the number of reactor years of operation because all the relays were replaced with a new model of relay. Hence, the time in service years reflects the time the current relays have been in use.

TABLE 4

RELAY TEST RESULTS BINNED BY TEST INTERVAL

	Test Interval, Months				
	1	2	6	18	Total
No. of plants	4	4	3	2	13
No. of failures	11	1	2	11	25
No. of relay tests	145,800	5,201	3,517	2,661	157,000

The 25 failures in 157,00 tests gives 1 failure per 6,280 tests. If each plant was tested at a twelve month interval the following number of tests would have been performed:

Total tests normalized for 12 month interval

145,800/12	=	12,150
5201/6	=	867
3517/2	=	1,758
2661/.667	=	3,990
Total		18,765

Dividing 18,765 total tests by 25 failures gives 1 failure being discovered every 751 tests.

If the same normalized calculation is made for an 18 month test interval, 1 failure would have been discovered every 500 tests (12,511/25).

The significance of these calculations will be discussed in Section 4.2

4.2 ESTABLISHMENT OF CRITERIA

The determination of an appropriate test interval should be based on established criteria. This report establishes four criteria for determining the appropriate subgroup relay test interval:

- Criterion one compares the surveillance interval to the number of failures being detected.
- Criterion two discusses system unavailability,
- Criterion three discusses wear to plant equipment, and
- Criterion four discusses plant transients.

Criterion (1). Extension of the surveillance interval is warranted if a large disparity exists between the number of tests being performed and the number of failures being revealed.

There are instances were certain components may be tested too frequently based upon their number of failures. In these instances, the frequency should be adjusted to correspond to the relative number of failures detected as shown through operating history. If many failures are occurring during the testing interval, the testing frequency should be increased. A "balance" between the reliability of a component and the frequency with which it is tested, must be established for each component in a plant.

Criterion (2). Extension of the surveillance interval should not significantly increase the unavailability of a system to perform its safety function.

Extending the surveillance interval will inherently increase the time that a failure could go undetected. Any extension of a surveillance interval should not significantly increase the system unavailability, if it does the surveillance interval should not be extended.

System unavailability (as related to subgroup relay failure) depends on how the relay fails (discussed in Section 4.1), the refuel cycle length and how long it takes to perform testing.

In instances where failures are time dependant, a correlation between the testing interval and the probability of failure can be made. When the failures are random, a judgement must be made based on the mean time between failures, and testing interval, relating this time to system

unavailability. In the case of subgroup relays the failures were determined to be random through research of the NPRDS reports.

Criterion (3). Extension of the surveillance interval may be warranted if it is causing unnecessary wear to other plant equipment

If, as a result of performing the surveillance test, there is an indication that other equipment is experiencing unnecessary wear then the surveillance frequency should be adjusted.

Criterion (4). The surveillance should not lead to plant transients.

The plant should not be placed in an unsafe or potentially unsafe condition as a result of surveillance testing. Nor should testing result in challenges to other plant safety equipment.

Criteria three and four are also set forth in NUREG 1366 to justify extending surveillance intervals. NUREG 1366 also establishes the criteria that a surveillance should perform its intended function. In the case of subgroup relays the surveillance does identify a relay that has failed as is. In half of the cases the relay failure was detected by the subject surveillance. Therefore, this criterion was not considered.

4.3 APPLICATION OF CRITERIA

Criterion 1 requires that the surveillance should detect failures within a reasonable ratio to the number of surveillances performed (testing interval).

A components reliability is based on two functions; (1) how often it fails and (2) how long the component stays failed (Criterion 1). Section 4.1 discusses both functions. How long the component stays failed is dependent on the testing interval and the mean time to repair. For simplicity, we will specify that the largest proportion of time a relay is failed is due to its failure remaining undetected rather than

the time to replace or repair it.

As summarized in Section 4.1 one failure is currently detected every 6,280 tests. If the test was being performed on a 12 month interval a failure would have been detected every 751 tests and, similarly, on an 18 month interval every 500 tests.

Therefore, given the reliability discussion from Section 4.1 and the above paragraph, the components are being tested too frequently even on an 18 month test interval.

An 18 month test interval satisfies Criterion 1.

Criterion 2 deals with system unavailability. Extending the surveillance frequency from monthly to 12 or 18 months will increase the time a failed relay could go undetected by either 11 or 17 months.

Using the information in Table 3, with a total of 103 time in service years, 25 failures and 13 plants analyzed, the rate of failure is 0.24 failures/plant with the mean time between failures of 23 months.

When analyzed individually, all plants with more than 1.0 "time in service years" have a mean time between failures of greater than 12 months. Some of these plants, however, do not have a mean time between failures of more than 18 months.

If an 18 month surveillance interval is used there is a greater possibility that a relay failure will have occurred and go undetected within this interval.

However given:

- a single active failure is accounted for in the accident analyses,
- equipment can be manually started, and
- a mean time between relay failures of 23 months

the system unavailability will not be increased significantly with

either a 12 or 18 month test interval.

Criterion 3 relates surveillance testing to wear on plant equipment. This study determined the diesel generators (DGs) and other components, such as high pressure safety injection pumps (HPSI) are overtested as a result of this surveillance. Plant personnel indicated that the diesel generators are sometimes required to be started solely due to this test. HPSI pumps are also started solely as a result of this test. In all cases the components are being tested more frequently than would be normally required.

Diesel generator starting is discussed in Section 10.1 of NUREG 1366 (Emergency Diesel Generator Surveillance Requirements). Although the NUREG did not specifically relate DG testing to subgroup relay testing, it was suggested that plants examine ways to reduce DG testing.

NUREG 1366 suggested several findings related to the negative aspects of DG fast starts,

- Ring and cylinder wear is approximately 40 times greater from fast starts than through normal wear.

- The turbocharger over speeds about 15% on fast starts.

- The governor must be tuned for maximum rate starting rather than long run reliability. This could cause instabilities during operation as the governor attempts to control rated speed after a fast power ramp. The potential for tripping the DG is increased if the engine over speed trip point is approached during these instabilities.

- Rapid upper camshaft bearing and cam wear are attributed to cold starting,

- Higher torsional vibration stresses are caused by going through the engine vibration critical speed points with a full fuel rack.

Based on the above, an attempt should be made to reduce the DG starts. The DGs are vital to plant safety and should not be overtested. The diesel generators are subjected to various surveillance tests. The tests requiring starting the DG include; subgroup relay tests, ESFAS functional tests, loss of offsite power tests, etc. The subgroup relay tests are usually performed more frequently than the other DG tests. The subgroup relay test can be performed concurrently with some planned DG required surveillances.

Diesel Generator starts are typically performed with the DG at ambient conditions with no pre-lubrication or warmup. Section 10.1 of NUREG 1366 discusses Generic Letter 84-15 (11) which states "[L]icensees are encouraged to submit changes to their Technical Specification[s] to accomplish a reduction in the number of [cold] fast starts". GL 84-15 includes a typical technical specification requiring a cold fats start every 184 days rather than every month.

The subgroup relay test frequency should not interfere with appropriate testing of the DGs. Most DG testing is required on 18 month intervals, therefore, a 12 month or 18 month subgroup relay test interval will cause only minimal or no unnecessary DG testing.

Criterion 4 deals with the potential for initiating plant transients as a result of testing.

This study found two instances of plant transients and one possible plant transients resulting from the testing of subgroup relays:

1) San Onofre Unit 2, on 1/16/84. The subgroup relay test resulted in a train "A" containment purge isolation signal (CPIS). All CPIS valves actuated.

2) Waterford 3, on 07/28/89. While performing the subgroup relay test, it was determined that the testing could result in the

potential for water hammer in steam generator blowdown lines. The ESFAS test procedure was revised.

3) Palo Verde Unit 2, on 03/25/86. While in mode 4, a MSIS actuation occurred on both trains A and B. This was attributed to a personnel error during the subject surveillance test. The relay test switch was turned to the next selection before the previous relays were reset.

Due to the potential consequences of an ESFAS actuation, it is undesirable to have any inadvertent actuations during testing.

The NRC findings from NUREG 1366 agree with the findings of criterion 4 from this report. The INPO LER database was the only source of information used to judge criterion 4 in this report.

Reducing the testing and therefore increasing the surveillance interval will decrease the probability of plant transients and satisfies the requirements of criterion 4.

5.0 RESULTS/RECOMMENDATIONS

As outlined in Section 4.3, the subject surveillance frequency is justified to be extended on all four criteria. Based on the critoria an 18 month test interval is justifiable for most plants. However, some plants have a mean time between failure of greater than 12 months but less than 18 months, therefore these plants may be able to justify a 12 month interval but not an 18 month testing interval.

The current surveillance test intervals are believed to have been originally based on engineering judgement. This judgement was based on the fact that the early types of relays were more prone to failure than those in use today. Given the wear on plant equipment (in particular the diesel generators) the low failure rate, small or no increase in system unavailability and a reduction in the potential for plant transients, the subgroup relay surveillance interval warrants extension. Operating experience has demonstrated this surveillance interval to be excessively short. Lengthening this surveillance test interval may slightly increase the probability of equipment not automatically actuating when required, alternate means of actuating the equipment is available. Increasing the test interval will however decrease the number of cycles of plant equipment. This also has the possibility of reducing plant transients caused by a large number of tests

An acceptable test interval based on the findings in this report is 18 months for most CE plants. However, some plants should have a 12 month testing interval if they do not adequately meet Criterion 2. This is based on information in Section 4.3 and the operating history.

6.0 REFERENCES

1) "Standard Technical Specifications for Combustion Engineering Pressurized Water Reactors," NUREG 0212, Draft Rev. 3 July 9, 1982.

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5) "RPS/ESFAS Extended Test Interval Evaluation," CEN-327, January 1989, (Task 513 Final report).

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7) "RPS/ESFAS Extended Test Interval Evaluation for 120 day Staggered Testing," (Task 620 Final Report) CE NPSD-576, December 1989.

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10) "Substandard, Refurbished, Potter & Brumfield Relays Misrepresented as New," NRC Information Notice 90-057, September 5, 1990.

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