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Docket No: 50-368

LICENSEE: Arkansas Power & Light Company

FACILITY: Arkansas Nuclear One, Unit 2

SUBJECT: SUMMARY OF MEETING FOR ARKANSAS NUCLEAR ONE AND THE INCIDENT OF SEPTEMBER 16, 1978 REGARDING OVERLOAD CONDITIONS ON STARTUP TRANSFORMER NO. 2 AND THE CONSEQUENT UNIT 2 CONTAINMENT SPRAY

A meeting was held on October 6, 1978 at Bethesda, Maryland regarding the subject as noted above. The morning session was dedicated to a briefing by I&E (Region IV) for the staff on the systems involved and the sequence of events that occured on September 16, 1978. The afternoon session was a question and answer period with the Arknasas Power and Light Company (licensee) the licensee's consultants and the NRC staff. A list of attendees is provided in Enclosure 1.

MORNING SESSION:

Design Features: At the request of the NRC staff, I&E (Region IV) discussed the design features of Arkansas Nuclear One, Unit 1 and Unit 2, with respect to systems involved in producing the scenario of events which occured on September 16, 1978. These design features are briefly discussed below.

Each of the two units of Arkansas Nuclear One, i.e., Unit 1 and Unit 2, have a dedicated unit auxiliary transformer and a dedicated startup transformer, each of which can supply the necessary alternating - current power to all of the respective unit auxiliaries, including both safety and non-safety loads. The unit auxiliary transformers are supplied from their respective unit generator. The unit startup transformers are both supplied through a single auto-transformer which is linked to the 500 kilovolt and 161 kilovolt sections of the station switchyard (See Enclosure 2).

In addition, a backup Startup Transformer No. 2 is provided which can serve both Unit 1 and Unit 2. This transformer is supplied directly from the 161 kilovolt section of the switchyard. However, Startup Transformer No. 2 does not have the capacity for carrying the full auxiliary loads of both units at the same time.

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On a given reactor unit trip, all of the unit auxiliary loads will be transferred automatically from the unit auxiliary transformer to the dedicated unit startup transformer. For Unit 1 and Unit 2, the dedicated startup transformers are designated as No. 1 and No. 3, respectively. This transfer will occur in both units, independently.

When unit auxiliary loads are being carried by the dedicated startup transformers and this source of power is lost for any reason, all of the unit auxiliary loads will be transferred automatically to the backup Startup Transformer No. 2. This transfer will occur in both units, independently.

When both units are being supplied by their respective startup transformers and the common source of power (the autotransformer) for the startup transformers is lost for any reason, then the auxiliary loads of both units will be automatically transferred to Startup Transformer No. 2. This automatic transfer will overload Startup Transformer No. 2 (exceeding the MVA rating) and also produce an excess voltage drop resulting in a degraded grid voltage condition at the safety and non-safety buses of both units.

With the existing design, the overloading of Startup Transformer No. 2 will result automatically on the failure of the autotransformer circuit feeding the two dedicated startup transformers when the failure occurs concurrently with the following events; (1) both units in either the startup or shutdown modes of operation, (2) trip of one unit while the other unit is in either the startup or shutdown mode of operation, and (3) simultaneous trip of both units.

Sequence of Events: The operating status of Arkansas Nuclear One prior to the incident at 13:19 hours on September 16, 1978 was as follows. Unit 1 was operating at 100% full power and auxiliary loads were being carried on the Unit 1 auxiliary transformer. Unit 2 was in Mode 3 (Hot Standby) in hot functional testing and preparing for initial criticality and power operation. The Unit 2 auxiliary loads were being supplied by startup transformer No. 3.

At about 13:19 hours the operating status of Unit 1 was interrupted by the failure of the Unit 1 "A" Loop Main Steam Line Isolation Valve Air Solenoid which allowed the valve to fail closed. This failure caused a Unit 1 reactor trip and turbine - generator trip. Since Unit 1 could no longer supply its own power, automatic transfer of the Unit 1 loads from the Unit 1 auxiliary loads to the Unit 1 Startup Transformer No. 1 occured. Unit 2 was already on Startup Transformer No. 3.

This transfer loaded the autotransformer with the full auxiliary loads of both units. At this point, the event should have terminated. However, as later learned, the autotransformer overcurrent relay had not been set for two unit operation and the relay tripped and caused a consequent opening of the circuit breakers feeding the two startup transformers. The loss of Startup Transformers No. 1 and No. 3 automatically then transferred the full auxiliary loads of both units to standby Startup Transformer No. 2 exceeding its MVA rating and producing a degraded voltage condition at the auxiliary buses (safety and non-safety) of both Unit 1 and Unit 2.

At this time, the relays at Unit 2 which act to protect the emergency safety features equipment from degraded low voltage isolated both engineered safety feature buses as designed. At the same time the Unit 2 Core Protection Calculator instrumentation registered trips which indicated loss of alternating current power to two instrument channels.

These instrument channels can receive a supply of alternating current power through two sources. They are (1) through four inverters, each of which obtains power from the station batteries (direct current) of the 480 volt normal alternating current input from the Engineered Safety Feature buses through current conditioning devices and (2) directly from the 480 volt engineered safety buses by bypassing the current conditioning inverters which is designated as the alternate or backup source.

During the event (the exact time has not yet been established), all four inverters transferred the power supply for vital alternating current buses to the alternate source. The exact cause of the transfer is not known but at any rate, this transfer to the alternate source should not have occured.

With the Unit 2 Engineered Safety Feature buses isolated as described above the alternate path could not provide power to the two vital AC buses. The loss of two out of four channels resulted in a fail-safe actuation of the Unit 2 Emergency Safety Features Actuation System. The two Unit 2 emergency diesels started and supplied power to the previously isolated engineered safety buses.

Thereupon, since the engineered safety features system was actuated, containment spray was initiated and dumped approximately 8000 gallons from the refueling water tank by way of the sprays to the containment. Also, the recirculation actuation system immediately cycled valves which momentarily opened a flow path between the refueling water tank and the containment sump. Gravity feed by way of the momentary flow path allowed approximately 40,000 gallons of borated water to be transferred from the refueling water tank to the containment sump. Approximately 50,000 gallons of borated water was now in the containment sump after this series of events.

Although not yet fully unravelled and precisely determined, a second full actuation of the Unit 2 Engineered Safety Feature Actuation System occured. All four Core Protection channels were tripped indicating a power pertubation on the inverters.

This sequence of events was finally terminated when manual actions reenergized Startup Transformers No. 1 and No. 3 and auxiliary loads were again supplied by offsite power. See Enclosure 3, Question 1 for a fiducial time sequence of the events described above.

MORNING SESSION DISCUSSION:

On September 28, 1978 the NRC staff had requested I&E (Region IV) to investigate and pursue staff questions regarding the event. The staff questions and the I&E responses are provided in Enclosure 3. The remaining time in the morning session was spent in discussing these items. Also, the question of Arkansas Nuclear One compliance with General Design Criteria No. 17 (GDC 17) was discussed in detail.

The design feature of automatic load transfer to startup transformer No. 2 as provided in the Arkansas Nuclear One design, provides a second immediate access circuit which exceeds GDC 17 requirements; however, the resulting overload of startup transformer No. 2 violates the independence requirements of GDC 17.

The Millstone fix for unit 2 for degraded grid voltage conditions includes a second level of undervoltage trip (about 92% of normal). This fix is also scheduled for installation of Unit 1 at the next scheduled refueling outage in early 1979. During the discussion it was noted that the Millstone fix is intended to protect the onsite safety related distribution systems from a degraded offsite grid voltage condition but not against degraded grid due to overload of an onsite startup transformer (it is effective, however, in this regard). Therefore, the Millstone fix is necessary in order to meet the GDC 17 requirements for independence between the offsite and onsite power system. However the Millstone fix is not considered pertinent to the evaluation of the offsite system design for conformance to GDC 17 requirements for independence between the two required offsite power circuits. For the case at hand, i.e., the Arkansas Nuclear One design feature in question is the automatic overloading on one of the required offsite power circuits to both units on the failure of the other offsite circuit.

AFTERNOON SESSION:

The licensee was questioned in great detail regarding the items discussed in the morning session. The items of primary concern discussed with the licensee were:

(1) Conformance of Arkansas Nuclear One to GDC 17.

(2) Operational Procedures for Manual Shedding of non-essential loads in the event both Unit 1 and Unit 2 are transferred to Startup Transformer Unit 2.

(3) The on-going investigation for inverter deficiencies and potential fixes.

(4) Procedures for verifying that cleanup from the effects of containment spray actuation on materials of the nuclear steam supply system were adequate.

At the close of the meeting the NRC staff stipulated the following actions which would be required to be completed prior to authorizing Arkansas Nuclear One, Unit 2 to proceed to Mode 2 - initial criticality.

(1) The question of compliance and conformance of Unit 2 to GDC 17.

(2) Investigate and correct the deficiencies of Unit 2 inverters.

(3) Implement procedures for the protection of plant equipment in the event both Unit 1 and Unit 2 are transferred to Startup Transformer No. 2.

(4) Implement chloride swipe tests as used at Browns Ferry for determining that cleanup procedures for stainless steel components are adequate.

Regarding Item 1 above, the staff informed the licensee that a staff position would be forthcoming on GDC 17. In addition, it was stated that I&E verification of the implementation and actions for correcting the noted deficiencies would be required prior to NRC authorization for Arkansas Nuclear One, Unit 2 Mode 2 operation.

Also, the licensee committed to evaluate the adequacy of inverters at Unit 1.

Leon B. Engle, Project Manager
Light Water Reactors Branch No. 1
Division of Project Management

Enclosures:
1. Attendance List
2. Simplified Line Diagram for Unit 1 and Unit 2
3. I&E Response to DSS/DOR Questions

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See next page

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ENCLOSURE 1

ATTENDANCE LIST FOR

MEETING, OCTOBER 6, 1978

ARKANSAS NUCLEAR ONE, UNIT 2

NRC STAFF

J. Beard	B	R. Reid	B
V. Benaroya	M	S. Rhow	A
W. Butler	M	F. Rosa	B
M. Chiramal	B	W. Russell	M
H. Conrad	B	R. Satterfield	B
B. Clayton	B	R. Scholl, Jr.	B
L. Engle	B	M. Srinvasan	B
R. Fitzpatrick	A	J. Stolz	M
G. Georgiev	M	R. Tedesco	B
S. Israel	M	D. Tondi	B
G. Kelly	M	T. Vincent	B
G. Klingler	B	G. Vissing	B
G. Lainas	B	E. Winzurger	B
P. Matthews	M	T. Westermann	B
R. McDermott	A	J. Zwloinski	M

ARKNASAS POWER & LIGHT COMPANY

J. Anderson	A	D. Rueter	A
D. Bennett	A	B. Terwilligen	A
T. Cogburn	A	D. Williams	A
J. Grisham	A		

BECHTEL CORPORATION

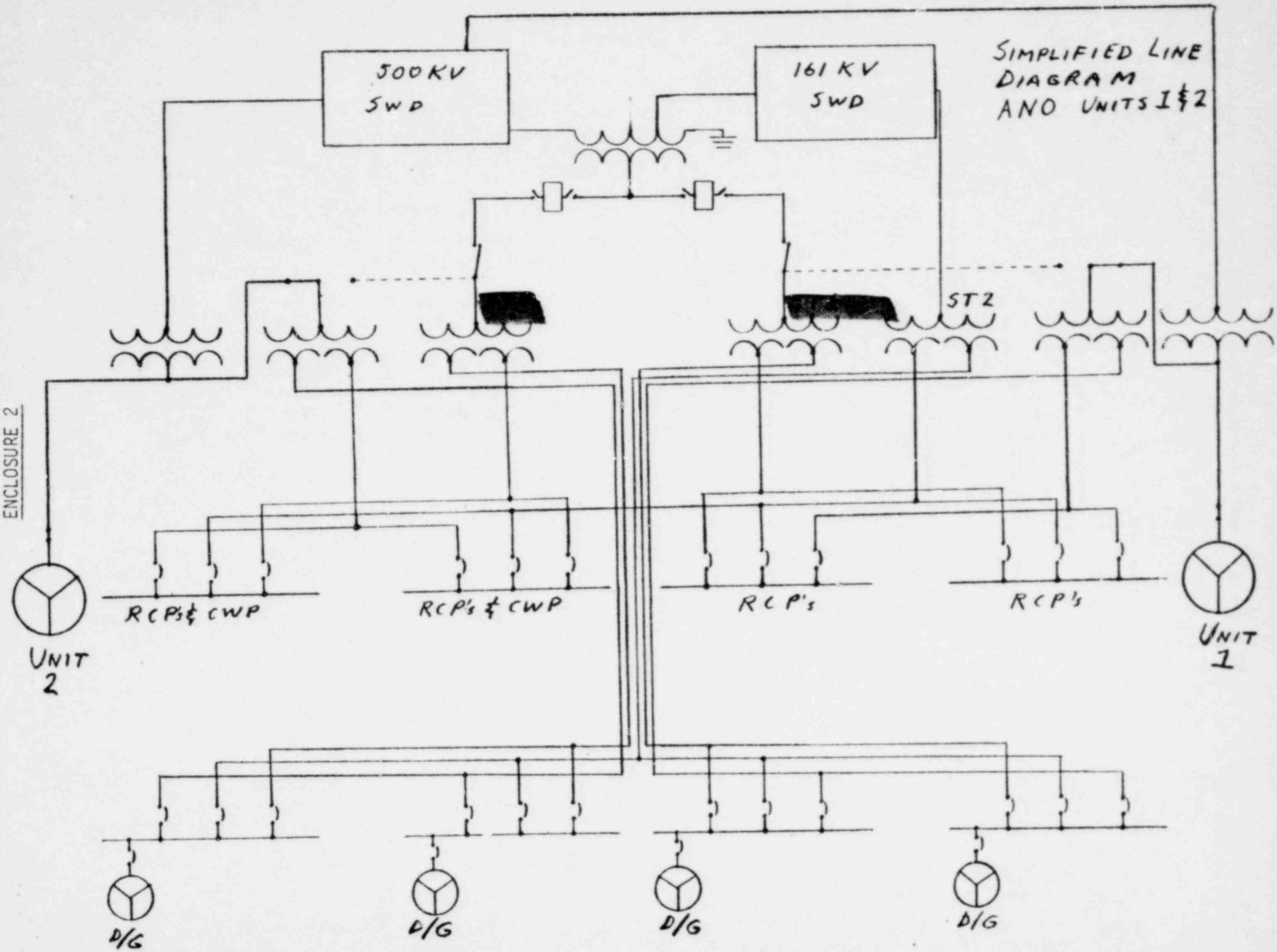
M. Iyer	A	C. Madsen	A

COMBUSTION ENGINEERING

J. Lewis	A

B - Attendance Both Sessions
M - Attendance Morning Session Only
A - Attendance Afternoon Session Only

ENCLOSURE 2


SIMPLIFIED LINE DIAGRAM ANO UNITS 1 & 2
500 KV SWD
161 KV SWD
ST 2
RCP's & CWP
RCP's & CWP
RCP's
RCP's
UNIT 2
UNIT 1
D/G
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D/G
D/G

ENCLOSURE 3

I&E RESPONSE TO DOR/DSS QUESTIONS

QUESTION 1

Provide a detailed description of the sequence of events that occurred (i.e., before, during and after) in the recent event of September 16, 1978, for both Units. Include a description of the interactions and interconnections between Units 1 and 2 in all applicable portions of the offsite power system.

RESPONSE

SEQUENCE OF EVENTS LEADING UP TO AND IMMEDIATELY FOLLOWING THE ANO-2 CONTAINMENT SPRAY ACTUATION

At approximately 13:19 on September 16, 1978, Arkansas Nuclear One was in the following status: Unit I was operating at 100%FP with normal RCS conditions. Auxiliary electrical loads were being carried on the unit auxiliary transformer. Unit II was in Hot Standby (Mode 3) in hot functional testing with RCS temperature/pressure at 546°F and 2240 psia. Unit II auxiliary electrical loads were being supplied by Startup Transformer No. 3. This steady state operating status was interrupted by the failure of the Unit I A Loop Main Steam Isolation Valve Air Solenoid which allowed the valve to fail closed. The following is the sequence of events which occurred as a result of the MSIV closure:

TIME	EVENT DESCRIPTION
13:19:04	The Unit One Reactor tripped on High Neutron Power sensed by RPS Channels A&C and the Turbine tripped concurrently.
13:19:04	Unit One's auxiliary electrical loads were auto-transferred to Startup Transformer No. 1.
13:19:13	The 500/161-22KV Auto-Transformer "C" Phase Overcurrent Relay tripped and the Lockout Relay actuated tripping OCB's B1025 and B1026, which supply power to Startup Transformers No. 1 and No. 3.
NOTE:	It was later discovered that this auto-transformer had not been set up for the loads required for two unit operation.
13:19:13	The Unit I and Unit II auxiliary electrical loads transferred to Startup Transformer No. 2.
NOTE:	This transformer is rated at 45MVA and is not designed to carry full auxiliary loads for both units. The AP&L load dispatcher received an overload alarm on this transformer during the event.

TIME	EVENT DESCRIPTION
13:19:21	Undervoltage Relays 27-1/2B5 and 27-1/2B6 tripped the Unit II 4160V ESF Buses 2A3 and 2A4, which are set to shed load at 92% of normal voltage.
NOTE:	Operating personnel noted that their indication showed that the ESF buses dipped to low as 3300 volts during the 8 seconds after the transfer to Startup Transformer No. 2 and before the undervoltage relay trips.
13:19:21	Unit II CPC Channels B&C tripped on Hi Local Power Density and Low DNBR. This trip was also sensed by the PPS and thus indicated loss of power supplies from Inverters 2Y22 and 2Y13, respectively.
NOTE:	When these CPC channels were restarted, the restart code indicated power failure had occurred.
13:19:21	Concurrent with the loss of power from 2Y22 and 2Y13 the Engineered Safety Features Actuation System (ESFAS) tripped giving start commands to all ESF components.
13:19:29	Unit II Emergency Diesel Generator 2DG2 came on-line and began supplying B loop ESF loads as ACB 2A408 closed.
13:19:31	Unit II Emergency Diesel Generator 2DG1 came on-line and began supplying A Loop ESF loads as ACB 2A308 closed.
Note:	It is estimated that the containment spray pumps ran approximately 2 minutes. Approximately 50,000 gallons of borated water ended up in the containment building sump. The majority of this water was apparently transferred via gravity feed from the Refueling Water Tank during the time the Recirculation Actuation System Valves were changing position.
13:19:29 to 13:19:31	Unit II CPC Channel D tripped due to an apparent power perturbation in Inverter 2Y24. However, there was not enough evidence to conclude that a failure of 2Y24 occurred at this time.
NOTE:	The PPS, CPC, and ESFAS were reset within about 3 minutes following the actuation. All were reset and behaved normally, indicating available power supplies from all inverters.

TIME	EVENT DESCRIPTION
13:24 to 13:26	A second full actuation of the Unit II ESFAS occurred. All four CPC channels tripped, indicating another power perturbation from the inverters. Since most of the ESF pumps were in pull-to-lock or otherwise bypassed by this time, no further containment spray occurred.
NOTE:	The Shift Supervisor who was on at the time of this occurrence later reported an attempt to re-energize Bus 2A3 at about this time which may have caused a spike in the power feed to the inverters, which were later found to be in "alternate" source.
13:29	An operator was dispatched to check the status of the Unit II inverters. The status found was as follows: 2Y22 -- AC & DC breakers open and the inverter was on "alternate" source. 2Y24 -- Fuse blown and the inverter was on "alternate" source. 2Y11 -- Inverter on "alternate" source. 2Y13 -- Inverter on "alternate" source.
13:49	The operator and an electrician returned to the inverter panels. 2Y11, 2Y13, and 2Y22 were reset to "normal" soruce. 2Y24, which had a blown fuse, was not reset.

QUESTION 2

Identify the power sources that were immediately available to achieve shutdown of both Units.

RESPONSE

Startup transformer #2 was available during and following the event. It is rated at 45 MVA and is not capable of carrying the full house loads for both Units I and II. When the auto-transformer lockout relays tripped and the combined Unit I and II auxiliary loads transfer to Startup Transformer #2 at 13:19, Operations personnel did not immediately relize the source of the problem and Startup Transformer #2 was operated under an overload condition until approximately 13:33. Overload alarms to the AP&L Transmission Dispatch Center indicated loads from 60.3 to 86.4 MVA and oil temperatures on the order of 110°C. Operations personnel, attempting to restore an Unit II circulating water pump, finally caused a trip of all four Unit I Reactor Coolant Pumps on undervoltage (set at 71.7% of 6.9 kv) at 13:33. At this time load shedding was initiated. Three of four Reactor Coolant Pumps on Unit II were tripped and two Reactor Coolant Pumps were restored to service on Unit I. The Unit I electric driven Emergency Feedwater Pump remained powered from Startup #2 transformer throughout the incident. The Unit I Emergency Diesel Generators were available but did not start during the incident. The Unit II Diesel Generators started and were tied to the ESF Buses 2A3 and 2A4.

QUESTIONS 3 & 4

Discuss the errors in operation (i.e., pre-operation check out errors, operator errors, etc.) to cause loss of offsite power and engineered safety features actuation to Unit 2, and identify the specific causes of the failures.

Describe in detail the failures that occurred in the offsite power and in the uninterruptable power supply system which lead to multiple degradation of the vital power supplies, and loss of the bus tie transformer. Specify the number of relay or systems that were improperly set.

RESPONSE

The loss of the Bus Tie Auto-transformer offsite power supply was caused by a time delayed overcurrent trip on "C" phase which tripped the lockout relay associated with the auto-transformer. This particular trip is designed to protect the auto-transformer from an overload condition, and was apparently set to trip for loads in excess of 58 MW. The auto-transformer itself is rated at 600 MVA and is easily capable of supplying both Unit I and Unit II auxiliary loads. Operational and Maintenance responsibilities for the auto-transformer belong to engineering organizations within AP&L other than the ANO staff. However, no engineering organization within AP&L recognized the necessity of re evaluating the auto-transformer protective relaying set points. This appears to be an engineering error.

The Unit II ESF actuation was caused by the loss of at least the green (Vital Bus #2 or Vital Bus B) and the yellow (Vital Bus #3 or Vital Bus C) 120 V AC "noninterruptable" power supplies.

The green vital bus is fed from inverter 2Y22 which was later found to have an improper set point in the low voltage DC input circuitry. This circuitry is designed to sense a low voltage DC input of 104 V DC and after a 10 second time delay, open the Battery Supply and Rectified AC Supply circuit breaker. This circuit was found to have a set point of 134 V AC and zero time delay. When the undervoltage relay on Unit II ESF Buses 2A3 and 2A4 operated to isolate 2A3 and 2A4, the DC input to 2Y22 fell to nominal battery voltage of 127 V DC which caused the low voltage DC input circuitry (set at 134 V DC) to trip both supply breakers to the inverter. The alternate emergency feed is powered from bus 2A4 and was not available until the Diesel Generator sequenced into the bus within about 8 seconds. Thus, the green vital bus was without a power supply until the diesel generator closed onto bus 2A4.

The yellow vital bus is fed from inverter 2Y13 which was found to have the correct low voltage DC input set point of 104 V DC but a time delay of 2 seconds rather than 10 seconds. Operators sent to check out the inverters approximately 10 minutes after the actuation found:

2Y13 -- transfered to Alternate Source
2Y11 -- transfered to Alternate Source
2Y24 -- fuse FU-2 blown, transferred to Alternate Source
2Y22 -- AC, DC input breakers tripped; transferred to Alternate Source.

Neither AP&L nor the inverter vendor representative, called to the site, could conclusively account for 2Y13 or 2Y11 being in the Alternate Source Mode. The Alternate Source for these inverters is supplied from bus 2A3 and thus would not have been available until the diesel generator closed on to bus 2A3. The vendor representative indicates that the static switch will not transfer from the inverter output to the Alternate Source unless that source is available; furthermore, having transferred to alternate source it will not transfer automatically back to the inverter output. Thus, it appears that the inverters 2Y11 and 2Y13 may have transferred to alternate source prior to the event. However, the mid-shift (0000 - 0800) supervisor and a day shift reactor operator indicated that they noted all inverters were normal during their plant tours (the day shift operator places his tour somewhere between 1000 and 1100 hours on September 16). A transfer to Alternate Source will give an inverter trouble alarm in the control room; however, 10 other inverter problems can initiate this alarm. As the fan failure alarm switches had been the cause of numerous inverter trouble alarms over the past several months, it was not uncommon to have the inverter trouble alarm and thus it may not have been noticed by the operators. The vendor representative indicated that the static switch operates on inverter failure, low inverter AC output (84 V AC) and high inverter output current (150 amp). He verified the inverter failure function and low AC output set points for all inverters. The high inverter output current set point is scheduled to be tested. The blown fuse on 2Y24 would have caused a transfer to alternate source on inverter failure. The reason for a blown fuse on 2Y24 could not be established conclusively although the vendor representative indicated that a high voltage transient on the rectified AC input could cause this fuse to blow. The table below summarizes the findings:

Inverter	Required Set Point Low DC Input	Required Set Point Time Delay	Set Point Found after 9/16/78 Low DC Input	Set Point Found after 9/16/78 Time Delay
2Y22	104 V DC	10 sec.	134 V DC	0 sec.
2Y24	104 V DC	10 sec.	104 V DC	0 sec.
2Y11	104 V DC	10 sec.	104 V DC	2 sec.
2Y13	104 V DC	10 sec.	104 V DC	2 sec.

The preoperational test verified the low DC input set point but did not verify the associated time delay for all inverters. The static switch transfer on low inverter output voltage and high inverter output current was also verified correct during preoperational testing. A lack of familiarity by startup personnel is responsible for the failure to verify the time delay set points, and similarly, by plant electricians is probably responsible for the incorrect set points found after 9/16/78. For example, there were two outstanding job orders issued on 7/3/78 and 7/24/78 to the plant electricial staff to repair 2Y22 as a result of seven different trouble reports initiated by the operation staff over the period of March to August 1978. However, no maintenance records exist to show what maintenance had been done, if any, to the inverters since the preoperational testing which was completed in August 1977.

QUESTIONS 5 & 6

Discuss plans to investigate the effects of the actuation of the containment spray (boric acid and sodium hydroxide) on the materials of the reactor system and on the equipment inside containment, and justify the adequacy of the clean-up operations for Unit No. 2.

Discuss any damage to the safety equipment (i.e., valves, pumps, motors, cable, sensors, etc.) of each unit, and provide justification for concluding that there was no damage and/or degradation to electrical, mechanical and piping components.

RESPONSE

Specific plans and completion status is as follows:

1) Surveillance testing was conducted on HPSI, LPSI, NaOH, and containment spray pumps to prove operability. All containment isolation valves inside containment were stroke-tested per operating surveillance procedures covering those valves.

2) Operational testing of the ECCS pumps per Section II was completed and no discernable degradation was noted on any pump.

3) The semiannual functional test of both H_2 recombiners was satisfactorily completed with no unusual responses noted.

4) Applicable sections of the Cold Shutdown Valve Stroke Test and Containment Isolation Valve Stroke Test were run with no discrepancies noted.

5) Results of sampling done to check for possibility of plugging or partial plugging of the containment spray nozzels from debris picked up from the containment sump indicated low solids content of the water in both trains. No large particles of debris were noted in any of the several samples taken. Hence, the possiblity of debris plugging is remote. Based on boron deposition in containment on surfaces wetted by the spray, it is also difficult to concieve of sufficient boron crystallization within the spray nozzels to plug or partially plug them. The maximum crystallization amounted to only a few mils on areas in containment where pools evaporated, concentrating the acid.

6) Oil residue in the sump area, apparently from the cables of the polar crane and other oily areas, was cleaned up immediately. All floor drains were flushed to the sump and the sump pumped down, and hand cleaned of sludge.

7) All electrical terminal/junction boxes and HSS cubicles were opened and cleaned. Efforts were documented with no significant findings other than evidence that water had been present as determined by boric acid streaking.

8) All safety related instrumentation was visually inspected and no evidence was found of damage or reasons to check further.

9) The polar crane was inspected and checked. No damage observed.

10) The operation of the refueling bridge was checked. Repair work is complete with the exception of the reinstallation of the TV equipment which will be left until needed.

11) CEA change mechanism was checked. No evidence of corrosion or problems were found.

12) RX vessel head studs were found with no evidence of corrosion at 3 intervals 120° apart.

13) Hydrogen Recombiners were meggared and functionally checked. No damage was found and meggar readings were within specified range.

14) All RCP oil reservoirs and junction boxes were checked for water. None was found and the junction boxes were dry. All RCP motors were meggared and complete with acceptable readings.

15) The moveable incore detection equipment, including the drive machines, were inspected and required cleaning was done. The only significant finding was minor water marks on the detector slip ring assembly which was cleaned.

16) The startup and safety excore channels were checked and inspected. All boxes and detectors were found to be good and in service with no damage or sign of water. The only exception was a detector connector which was evidently damaged during the inspection. It was repaired.

17) Both containment sump level transmitters and their associated loops were checked and recalibrated.

18) Inverters which caused the initiation were checked out and tested.

19) All CEA power and reed switch position transmitters were visually checked without cause for further test until hot conditions are established. These devices were evidently protected by the missile shield.

20) Operation activities included the draindown of the LPSI, HPSI, and containment spray systems to restore water quality and ensure no further contamination; operational and visual checks with all I&C personnel on all containment fire protection equipment, and repetition of all stroke test on containment motor operated valves. This item will be completed prior to heatup.

21) The CEA extension shaft coupling tool and RX vessel tensioning tools showed minor rust from the atmospheric conditions. Both were cleaned.

22) Other minor items found and corrected on a case-by-case basis included several PAX phones out-of-service, misc. lights out, minor gaitronics problems, and various water spotting and streaking.

23) Containment Spray Header hangers and snubbers were visually inspected with no evidence of over use or damage.

24) An inspection was made of specific locations of installed insulation 1) areas around the pressurizer relief valve where insulation was removed for valve repair, 2) inspection under the insulation at the top transition nozzel on each steam generator, 3) inspection under the insulation on each main steam line, and 4) the removal, disassembly, and inspection of mechanical snubber 2PSA-10. No problems found. The remainder of the temporary insulation was inspected without any signs of degradation as a result of the spray.

The above completes the Unit 2 containment cleanup.

Temperature recorders for Motor Winding Temperatures on Unit 1 Service Water, Circulating Water and RCS Makeup Pumps indicated a temperature rise of only 15-20°F due to undervoltage operation. This indicates that no significant damage occurred to motors operated for the short period during which low voltage existed. Oil and gas samples taken from Startup Transformer #2 do not indicate any degradation of this transformer.

QUESTION 7.

Describe how the event was terminated, and identify the instrumentation that was available to the operator to follow the course of the event and allow him to conclude that, in fact, there was no LOCA.

RESPONSE

The Unit 2 ESF actuation was terminated by placing all safeguards pumps in the pull-to-lock position and resetting the Plant Protection System to clear the actuation signals. Pressurizer Pressure and level instrumentation was available and indicated normal. Containment Pressure indication was available and indicated a gradual increase of about 1 psi. This instrumentation thus indicated that no LOCA had occurred.

QUESTION 8

Provide the plans that will prevent recurrence of the event, and identify any design deficiencies (and modifications) that have been identified as a result of the incident.

RESPONSE

A Task Force was appointed on September 18 to establish and review the sequence of events in relation to functional reliability, component reliability, and initiation of changes necessary to prevent a future recurrence.

The preliminary investigation has disclosed three problem areas, thus far. They are:

A. The 22 KV tertiary bus overcurrent relays were set for Unit 1 conditions only. These were reset for Unit 1 and Unit 2 on September 26.

B. The trip voltages and delay timers for two of the inverters were set incorrectly and caused the inverters to not lock in on DC when the AC primary was lost. The transfer to alternate source was futile since the alternate source is powered by the same bus as the primary source. The inverters have been reset.

The investigation of the Task Force is continuing. The final report will make recommendations for any additional changes in equipment or design configuration to prevent the future recurrence of a similar sequence of events.

QUESTION 9

Justify the adequacy of the design for pre-selecting both Units to startup transformer (SU) #2 simultaneously, since the capacity of (SU) #2 is not designed to carry all the loads of both Units, and discuss the adequacy of the sizing of the transformer shared by both Units.

RESPONSE

Both units were not pre-selected to ST #2 as the preferred off-site power source. ANO-1 pre-selected to ST #1 and ANO-2 which was being supplied from ST #3 had ST #2 selected as its backup off-site power source.

ST #2 is capable of supplying the emergency loads on one unit while simultaneously supplying the necessary auxiliary loads required to achieve an orderly shutdown on the other Unit. ST #2 will, without damage, withstand the full auxiliary loads from both Units long enough to shed unnecessary loads. The effect of undervoltage on the Units due to ST #2 being overloaded for a short period of time is discussed in item 11 below.

QUESTION 10

Provide justification and specific basis for allowing Unit 1 to return to power.

RESPONSE

With the repair of the failed solenoid valve on the Unit 1 MSIV, no other damage to system components was found. No safeguards actuation occurred and the post trip recovery of Unit 1 proceded normally after load shedding on the #2 Startup Transformer restored system voltage. Unit 2 was placed in cold shutdown and Unit 1 was returned to operation.

QUESTION 11

Discuss the applicability of this event to DOR letter dated June 3, 1977 regarding degraded grid voltage.

RESPONSE

DOR letter, dated June 3, 1977, required that AP&L access the susceptibility of the ANO-1 safety related electrical equipment with regard to (1) sustained degraded voltage conditions at the offsite power sources, and (2) interaction between the offsite and onsite emergency power systems.

The ANO-1 non ES to ES bus tie breakers did not open on undervoltage. There were, however, no ES equipment malfunctions or damage due to the undervoltage. The Emergency Feedwater System operated according to design, and the service water pumps, one make-up pump and four reactor building fans ran prior to, during and after the event. Apparently no modifications are required to ANO-1 to accommodate this event.