July 16, 2002

Mr. A. C. Bakken III
Senior Vice President
Nuclear Generation Group
American Electric Power Company
500 Circle Drive
Buchanan, MI 49107-1395

SUBJECT: D. C. COOK NUCLEAR POWER PLANT, UNITS 1 AND 2
NRC INSPECTION REPORT 50-315/02-07(DRP); 50-316/02-07(DRP)

Dear Mr. Bakken:

On June 19, 2002, the NRC completed a special inspection at your D.C. Cook Nuclear Power Plant, Units 1 and 2. The enclosed report documents the inspection findings which were discussed on June 27, 2002, with you and other members of your staff.

This inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, and interviewed personnel.

On June 12, 2002, an Alert emergency declaration was made by your staff following a catastrophic failure of a current transformer in the 345 kV switchyard. Automatic and manual actions following the current transformer failure resulted in a complete loss of the preferred offsite power supply to both units. Based on the risk and deterministic criteria specified in Management Directive 8.3, "NRC Incident Investigation Program," and Inspection Procedure 71153, "Event Followup," a Special Inspection was initiated in accordance with Inspection Procedure 93812, "Special Inspection." The purpose of the Special Inspection was to evaluate the facts, circumstances, and your staff's actions surrounding this event. A charter was developed to focus the inspection (reference ADAMS accession number ML021650216).

Overall, we concluded that your staff's response to this event was adequate. This report discusses a finding of very low safety significance associated with your failure to justify deviations from vendor recommended preventive maintenance schedules for 345 kV switchyard current transformers. However, this finding was determined not to constitute a violation of NRC regulatory requirements. In addition, we noted some coordination and communication problems, including inaccuracies in the initial notification made to your emergency response organization and the lack of coordination regarding response of offsite fire response personnel.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosures will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

We will gladly discuss any questions you have concerning this inspection.

Sincerely,

/RA/

Geoffrey E. Grant, Director
Division of Reactor Projects

Docket Nos. 50-315; 50-316
License Nos. DPR-58; DPR-74

Enclosure: Inspection Report 50-315/02-07(DRP);
50-316/02-07(DRP)

cc w/encl: J. Pollock, Site Vice President
M. Finissi, Plant Manager
R. Whale, Michigan Public Service Commission
Michigan Department of Environmental Quality
Emergency Management Division
MI Department of State Police
D. Lochbaum, Union of Concerned Scientists

DOCUMENT NAME: G:\COOK\ML022000280.WPD

To receive a copy of this document, indicate in the box:"C" = Copy without enclosure "**E**"= Copy with enclosure"**N**"= No copy

OFFICE	RIII		RIII		RIII		RIII		RIII	
NAME	HWalker:smb		SBurgess		SOrth		KRiemer		GGrant	
DATE	07/12/02		07/12/02		07/12/02		07/12/02		07/16/02	

OFFICIAL RECORD COPY

<u>ADAMS Distribution</u>:
WDR
DFT
JFS2
RidsNrrDipmIipb
GEG
HBC
BJK1
C. Ariano (hard copy)
DRPIII
DRSIII
PLB1
JRK1

U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-315; 50-316
License Nos:	DPR-58; DPR-74
Report No:	50-315/02-07(DRP); 50-316/02-07(DRP)
Licensee:	American Electric Power Company
Facility:	D. C. Cook Nuclear Power Plant, Units 1 and 2
Location:	1 Cook Place Bridgman, MI 49106
Dates:	June 13 through 19, 2002
Inspectors:	J. Lennartz, Senior Resident Inspector, Palisades K. Coyne, Resident Inspector H. Walker, Electrical Inspector, RIII
Approved by:	D. Passehl, Acting Chief Branch 6 Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000315-02-07(DRP), IR 05000316-02-07(DRP), Indiana Michigan Power Company, 06/13-19/2002, D. C. Cook Nuclear Power Plant, Units 1 and 2. Special Inspection.

The special inspection was conducted by resident and region-based inspectors. The inspectors identified one Green finding. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply are indicated by "No Color" or by the severity level of the applicable violations. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. Inspector Identified Findings

Cornerstone: Initiating Events

- Green. The inspectors identified a finding of very low safety significance for the failure to perform preventive maintenance on 345 kV switchyard current transformers in accordance with vendor recommended schedules without adequate justification for the deviations. Specifically, the licensee tested 345 kV current transformers less frequently than recommended by the vendor and did not perform several recommended tests. The inspectors determined that this finding did not constitute a violation of NRC requirements.

  The inspectors concluded that testing switchyard equipment less frequently than recommended by the vendor credibly affected the objective of the initiating events cornerstone of reactor safety. Performance of preventive maintenance testing that was less conservative than vendor recommendations could result in the failure to detect and repair component degradation, which could increase the likelihood of component failures. Consequently, the inspectors concluded that this issue could increase the likelihood of loss of offsite power events and limit the ability of the licensee to mitigate power grid instability events. However, due to the availability of redundant power supplies to safety-related equipment, the inspectors determined that this issue was of very low safety significance.

B. Licensee Identified Violations

- None

Report Details

Note: A list of documents reviewed during the inspection is included at the end of the report. Also, Final Safety Analysis Report (FSAR) Figure 8.1-2A, “Simplified Offsite Power Sources, D. C. Cook Nuclear Plant," is attached at the end of the report for reference.

Summary of Plant Status:

Unit 1 was at approximately 68 percent power and Unit 2 was at 100 percent power for the duration of the event.

4OA3 Event Followup (93812)

.1 Sequence of Events for Alert Emergency Condition

a. Inspection Scope

The inspectors reviewed logs from the Technical Support Center (TSC), Operations Support Center (OSC), Emergency Operations Facility (EOF), and the control room; and the event chronology completed by licensee personnel. The inspectors also interviewed several D. C. Cook Nuclear Plant and American Electric Power (AEP) employees to validate the sequence of events. Based on these reviews and interviews, the inspectors developed a sequence of events for the June 12, 2002 Alert emergency condition resulting from a catastrophic failure of a 345 kV switchyard current transformer.

b. Findings

On June 12, 2002, an Alert emergency condition that affected both Units was entered following a catastrophic failure and resultant fire of the phase 1 current transformer for the 345 kV switchyard “L” breaker. The 345 kV switchyard connected the Unit 1 main generator to the offsite electrical grid and normally provided Train “B” preferred offsite power for both units. The catastrophic failure of the current transformer and subsequent switchyard switching actions resulted in the loss of the preferred offsite power source to Unit 1 and 2. The following plant conditions of significance existed prior to the Alert emergency condition:

- Unit 1 was at approximately 68 percent power;
- Unit 2 was at 100 percent power;
- Unit 2 East (Train A) Essential Service Water (ESW) pump was removed from service for planned pump replacement and was therefore inoperable. This placed Unit 2 in a 72 hour limiting condition for operation in accordance with Technical Specification (TS) 3.7.4.1.a;
- For the planned Unit 2 East ESW pump replacement, the Unit 1 West (Train B) ESW pump was also inoperable because it was hydraulically cross tied to Unit 2

East ESW pump in accordance with plant procedures. Therefore, Unit 1 was also in a 72 hour limiting condition for operation in accordance with the corresponding Unit 1 TS;

- Work was in progress in the 345 kV switchyard to support replacement of the “M1” breaker.

- Unit 1 Main Generator Output “K1” Breaker was out of service due to a problem with the alignment of the disconnect switch which had been discovered on June 9, 2002, during startup activities following a scheduled refueling outage. Consequently, the Unit 1 main generator was connected to the offsite grid through only the Unit 1 Main Generator Output “K” breaker; and

- Switchyard breaker “BD,” Reserve Feed Cross Tie Breaker, was in the normally open position. This alignment allowed the preferred offsite power source to be supplied to Train “A” for Unit 1 and Unit 2 through 765 kV Transformer 4 and to Train “B” for Unit 1 and Unit 2 through 345 kV Transformer 5.

The inspectors determined the following sequence of events resulted in the Alert emergency condition and its subsequent termination on June 12, 2002:

Time	**Event Description**
1345	Fault detected on “L” breaker in 345 kV switchyard because of catastrophic failure (explosion and subsequent fire) of the “L” breaker phase 1 current transformer. • 345 kV switchyard breakers “L,” “L1,” “K2,” “N2,” “M2,” and “BC;” and 765 kV switchyard breakers “A2" and “B2" automatically opened due to the fault which resulted in a loss of: - 345 kV switchyard Bus #2; - 765 kV Transformer 4; and - Train “A” preferred offsite power source to Unit 1 and 2 safeguards equipment. A second fault was triggered less than 1 second into the event on the “M” breaker. • The fault automatically opened the 345 kV switchyard “M” breaker. The licensee subsequently determined that collateral damage from the faulted “L” breaker (which was physically located next to the “M” breaker) casued the "M" breaker fault.

1345 Ft. Wayne Operations Center notified the Cook Nuclear Plant Control Room Operators of the fire in the switchyard.

Control Room operators took the following actions:

- dispatched an ambulance and fire brigade to the switchyard;
- requested assistance from the Lake Township Fire Department; and
- dispatched the work control center Senior Reactor Operator (SRO) to the switchyard to provide oversight and direct communications with the control room.

1345 Unit 1 entered TS 3.0.5 due to the loss of Train "A" preferred offsite power source to safeguards equipment combined with the U1 West (Train B) ESW being inoperable as a result of the pump being hydraulically cross tied to the inoperable Unit 2 East ESW header.

- Technical Specification 3.0.5 required that within 2 hours actions be initiated to place the unit in a Mode in which the applicable Limiting Condition for Operation did not apply by placing it in at least Mode 3, Hot Standby, within the following 6 hours.

1359 AEP Transmission and Distribution personnel in the switchyard at the time of the explosion requested, and were granted, permission from the Ft. Wayne Operations Center to open the remaining breakers in the switchyard to isolate the fault. The request was based on the concern for the safety of the other individuals in the switchyard.

- The 345 kV switchyard breakers "N" and "N1" were opened resulting in a loss of Train "B" preferred offsite power source to both Unit 1 and Unit 2 safeguards equipment.
- AEP Transmission and Distribution personnel also requested, and were granted, permission from Ft. Wayne Operations Center to open the Unit 1 Main Generator Output Breaker, "K" breaker. However, an interlock with the control room switch, as designed, prevented the breaker from opening. When the action to open the "K" breaker was taken, AEP personnel in the switchyard and Ft. Wayne Operations Center personnel thought that Unit 1 had tripped as a result of the initial explosion.

1359 Unit 2 entered TS 3.0.5 due to loss of Train “B” preferred offsite power source to safeguards equipment combined with the East (Train A) ESW pump out of service for planned maintenance.

- Technical Specification 3.0.5 required that within 2 hours actions be initiated to place the unit in a Mode in which the applicable Limiting Condition for Operation does not apply by placing it in at least Mode 3, Hot Standby, within the following 6 hours.

1405 Alert emergency condition declared based on emergency initiating condition H-4, “Fire or Explosion Affecting Plant Operations.”

1406 Ft. Wayne Operations Center personnel requested permission from the Cook Nuclear Plant Control Room operators to open the Unit 1 Main Generator Output “K” Breaker.

- Control room operators denied request to open the “K” breaker as that would have resulted in a Unit 1 trip with a loss of normal heat sink.

  - The unavailability of the preferred offsite power source would have resulted in a loss of forced circulation in the primary coolant system and loss of the main condenser for heat removal. Additionally, both emergency diesel generators would have been required to power the engineered safeguards equipment.

1415 Cook Nuclear Plant emergency response personnel notified Berrien County Sheriff of the Alert emergency condition.

1417 Cook Nuclear Plant emergency response personnel notified Michigan State Police of the Alert emergency condition.

1418 Cook Nuclear Plant emergency response personnel notified NRC Operations Center of the Alert emergency condition.

1431 Cook Nuclear Plant OSC activated.

1442 Cook Nuclear Plant TSC activated.

1500 Cook Nuclear Plant EOF activated.

1545 Two-hour time limit of the action statement of TS 3.0.5 for Unit 1 expired.

- Technical Specifications required Unit 1 to be in Hot Standby, Mode 3, within the next 6 hours.

1559 Two-hour time limit of the action statement of TS 3.0.5 for Unit 2 expired.

- Technical Specifications required Unit 2 to be in Hot Standby, Mode 3, within the next 6 hours.

1651 Switchyard breaker “N1” closed.

- Preferred offsite power source restored to Unit 1 and Unit 2 Train “B” safeguards equipment via 345 kV Transformer 5.

- Train “B” of preferred offsite power remained inoperable pending verification of proper breaker alignment and verification that voltages were acceptable.

1657 Switchyard breaker “BD” closed.

- Preferred offsite power source restored to Unit 1 and Unit 2 Train “A” safeguards equipment via 345 kV Transformer 5.

- Both trains of preferred offsite power restored to Unit 1 and Unit 2 via 345 kV Transformer 5 from one out of the six offsite lines into the 345kV switchyard but remain inoperable pending verification of proper breaker alignment and verification that voltages are acceptable.

1740 Verification of off site voltages indicated that 345 kV Transformer 5 voltage was less than the minimum required for operability.

2115 Following review and evaluation of a request for a Notice of Enforcement Discretion (NOED) from licensee personnel, NRC verbally granted the NOED to extend the time required to shut down Unit 1 and Unit 2 by 10 hours. The extension was to allow plant personnel time to restore the Unit 2 East ESW pump to an operable status.

Unit 2 East ESW pump started for surveillance testing after pump replacement was completed.

2123 Unit 1 exited TS 3.0.5.

- Unit 1 West ESW pump returned to operable status when cross tie to Unit 2 East ESW pump was closed, per plant procedures, for surveillance testing of the Unit 2 East ESW pump following maintenance.

2157 Unit 2 exited TS 3.0.5.

- Unit 2 East ESW pump restored to an operable status.

2238 765 kV switchyard breaker “B2” closed which energized 765 kV Transformer 4.

2242 765 kV switchyard Breaker “A2,” Unit 2 Main Generator Output Breaker, closed.

2308 345 kV switchyard breaker “BD,” Reserve Feed Crosstie, opened.

2309 345 kV switchyard breaker “BC,” Reserve Feed Supply Breaker, closed

- 765 kV Transformer 4 and 345 kV Transformer 5 in split configuration.
- 765 kV Transformer 4 providing preferred offsite power to Unit 1 and Unit 2 Train “A” safeguards equipment.
- 345 kV Transformer 5 providing preferred offsite power to Unit 1 and Unit 2 Train “B” safeguards equipment.

2347 Both trains of preferred offsite power are operable.

- 765 kV Transformer 4 and 345 kV Transformer 5 voltages meet minimum requirements of operablility while aligned in split configuration.

2354 Alert emergency condition terminated.

.2 Adequacy of Licensee’s Evaluation of “L” Breaker Failure

a. Inspection Scope

The inspectors reviewed the charter developed for the licensee’s root cause evaluation team to determine if the resources assigned to the evaluation team and the defined scope of the evaluation would adequately evaluate the cause of the “L” breaker failure and assess the licensee's response to the event.

b. Findings

The inspectors noted that two multi-disciplined teams were assigned to complete the root cause evaluation for Condition Report 02163045, “1-52-L has had a catastrophic failure, resulting in a loss of Offsite Power Sources supplied to Reserve Feed.” One team was assigned to evaluate the root cause of the breaker failure. The second team was assigned to evaluate the licensee’s overall effectiveness in responding to the event regarding areas such as emergency response, switchyard recovery, operations response, and switchyard management.

The inspectors concluded that the resources assigned to the licensee’s root cause evaluation team and the scope of the evaluation were adequate to evaluate the breaker failure. However, the root cause evaluation was scheduled to be completed on July 18, 2002, and therefore the inspectors could not assess the adequacy of the evaluation.

.3 Status of Maintenance on "L" Breaker

a. Inspection Scope

The inspectors reviewed the history of corrective and preventive maintenance, testing, and the vendor recommended preventive maintenance activities for the phase 1 "L" breaker current transformer to evaluate the adequacy of corrective and preventive maintenance activities.

The inspectors also reviewed condition reports that had been entered into the licensee's corrective action program regarding identified maintenance problems associated with switchyard breakers to assess corrective actions taken for past problems.

b.1 Recent Corrective Maintenance

No findings of significance were identified. However, the inspectors noted that the "L" breaker was replaced following a catastrophic failure of the phase 2 current transformer in 1990.

b.2 Adequacy of Preventive Maintenance

The inspectors identified a finding of very low safety significance for the licensee's failure to adequately justify deviations from the vendor recommended 345 kV switchyard current transformer preventive maintenance schedules. The inspectors determined that this finding did not constitute a violation of NRC requirements.

Description

The inspectors reviewed the licensee's preventive maintenance program for 345 kV switchyard current transformers. The vendor's preventive maintenance recommendations included annual inspections and transformer oil analysis every 2 years. The inspectors reviewed historical maintenance activities on the "L" breaker current transformers and determined that preventive maintenance activities were last performed in October 1998. Although the periodicity of preventive maintenance activities was consistent with AEP system guidelines for maintenance frequencies, the frequency was not consistent with vendor recommendations. Additionally, the vendor recommended several tests, including oil dielectric strength, oil acid factor, and a measurement of the resistance of the current transformer primary to compare with the results in the test report, which the licensee did not periodically perform.

During followup discussions with the licensee's electrical maintenance and engineering staff, licensee personnel stated that the types of testing performed and the testing frequencies were based on AEP system operating experience rather than vendor recommendations. However, licensee personnel were unable to readily provide specific operating experience data that justified the four-year preventive maintenance testing frequency. Licensee personnel subsequently determined that there were approximately one hundred twenty-six 345 kV current transformers in the AEP system similar in design to those located in the D.C. Cook 345 kV switchyard. Since 1990, there have been two catastrophic failures of this type of current transformer (both associated with the Cook 345 kV switchyard "L" breaker), and no current transformers of this type had been removed from service based on preventive maintenance testing.

Following the June 12, 2002 current transformer failure, AEP performed oil sampling on Cook 345 kV switchyard breakers for analysis. The oil samples and analyses were completed as part of the licensee’s extent of condition evaluation and were performed approximately 3 months prior to the time that the oil would have been analyzed based on the normal scheduled frequency. During the oil sampling, AEP personnel identified two current transformers associated with the "N1" breaker which were last sampled in September 1998 with gas analyses results significantly above the acceptable level. Based on this result, licensee personnel replaced the "N1" breaker current transformers and returned the breaker to service on June 29, 2002. The inspectors reviewed the AEP system operating experience data and were unable to conclude that this data adequately justified a deviation from vendor recommended preventive maintenance schedules.

<u>Analysis</u>

The inspectors assessed the licensee's failure to perform 345 kV switchyard preventive maintenance activities in accordance with vendor recommendations using the significance determination process (SDP). The inspectors concluded that testing switchyard equipment less frequently than recommended by the vendor credibly affected the objective of the initiating events cornerstone of reactor safety. Specifically, performance of preventive maintenance testing that was less conservative than vendor recommendations could result in the failure to detect and repair component degradation, which could increase the likelihood of component failures. Consequently, the inspectors concluded that this finding could increase the likelihood of loss of offsite power events and limit the ability of the licensee to mitigate power grid instability events. Therefore, the finding was more than a minor concern.

The inspectors performed a Phase 1 SDP assessment of the finding and determined that the finding was of very low safety significance (Green) based on the following:

- The finding did not contribute to the likelihood of a primary or secondary system loss of coolant initiating events;

- The finding did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment would not be available. Specifically, during the “L” breaker failure on June 12, 2002, neither unit tripped. Additionally, due to the continued availability of both diesel generators and the alternate offsite power supply during the event, the inspectors determined that redundant power supplies were available to mitigating equipment;

- The finding did not increase the likelihood of an internal or external flood; and,

- Based on discussions with the Region III Senior Reactor Analyst, the inspectors concluded that the finding did not result in an increase in the likelihood of core damage scenarios associated with a fire initiating event. Specifically, although the failure of the "L" breaker resulted in a localized fire in the switchyard, this issue did not result in a fire within the protected area that adversely impacted mitigating equipment credited in the external event probabilistic risk assessment.

Enforcement

The inspectors evaluated the licensee's failure to adequately justify deviations from the vendor recommended 345 kV switchyard current transformer preventive maintenance schedules relative to NRC regulatory requirements. The licensee considered non-safety-related 345 kV switchyard components to be within the scope of the Maintenance Rule (10 CFR 50.65) and controlled the performance of these components under the preventive maintenance program in accordance with 10 CFR 50.65(a)(2). However, based on switchyard performance within a 2-year maintenance rule monitoring period, the inspectors concluded that this single functional failure of the preferred offsite power supply did not indicate that licensee preventive maintenance activities ineffectively controlled offsite power functional capability. Consequently, the inspectors determined that this issue did not represent a violation of NRC requirements. Therefore, the licensee's failure to perform preventive maintenance on 345 kV switchyard current transformers in accordance with the vendor recommended schedules without adequate justification for the deviation was identified as a Finding of very low safety significance (FIN 50-315, 50-316/02-07-01).

.4 Assessment of Safety Significance of "L" Breaker Failure

a. Inspection Scope

The inspectors reviewed the circumstances surrounding the failure of the "L" switchyard breaker in order to assess the risk significance of the event. The inspectors reviewed plant conditions existing at the time of the event to evaluate the potential for loss of safety system functions.

b. Findings

The inspectors assessed the loss of the preferred offsite power supply to determine the risk impact of the "L" breaker failure. The inspectors considered the following during this evaluation:

- Both units remained stable during the event. No primary or secondary transients occurred as a result of the switchyard failure.

- Continuity of power, with redundancy, was maintained to all safety busses in both units. The alternate offsite power supply and all four diesel generators remained operable during the event. Electrical power was continuously supplied to the 4kV reactor coolant pump and safety busses throughout the event via the associated unit's main generator via the normal auxiliary transformers.

- With the exception of the Unit 2 East ESW pump, all significant engineered safeguards' equipment was operable in both units during the event. The availability of hydraulic unit cross ties in the component cooling water, essential service water, charging, and auxiliary feedwater systems provided additional redundancy in the event of unanticipated failures.

- Although degraded offsite voltage extended the preferred offsite power supply recovery time and necessitated issuance of an NOED to permit continued operation of both units, this additional time did not result in an unacceptable increase in risk. The adequacy of the licensee's basis for the NOED is discussed in Section 4OA5 below.

Based on the above factors and discussions with the Region III Senior Reactor Analyst, the inspectors concluded that this event was of very low safety significance.

Degraded Operation of the Unit 1 Reserve Auxiliary Transformers

Following a Unit 1 manual reactor trip on June 14, 2002, the licensee determined that the recently installed Unit 1 load tap changing reserve auxiliary transformers 101AB and 101CD did not perform as designed following an automatic load transfer from the normal auxiliary transformers. Although the reserve auxiliary transformers adequately powered associated electrical busses, the voltage controlling capability of the transformers was degraded due to a malfunction of the transformers' voltage controller. Because improper operation of the reserve auxiliary transformers could have potentially impacted the ability of the licensee to mitigate the degraded voltage conditions experienced during the June 12, 2002, switchyard event, the inspectors reviewed this issue to determine if it increased the risk significance of the "L" breaker failure.

The inspectors concluded that this reserve auxiliary transformer malfunction did not increase the significance of the "L" breaker failure. The inspectors noted that the 4kV reactor coolant and safety-related electrical busses adequately transferred to the reserve auxiliary transformers following the June 14, 2002, reactor trip. Additionally, the reserve auxiliary transformers maintained continuity of power to the associated electrical buses, within acceptable voltage limits, following the reactor trip. Based on the acceptable performance of the reserve auxiliary transformers following the June 14, 2002, reactor trip, the inspectors concluded that, although the voltage control capability of the reserve auxiliary transformers was degraded, this condition did not result in a significant risk increase for the "L" breaker failure.

.5 Equipment Response Anomalies

a. Inspection Scope

The inspectors reviewed the sequence of events regarding switchyard breaker operations that automatically occurred following the initial explosion and discussed with AEP Transmission and Distribution personnel and D.C. Cook Nuclear Plant Operations personnel the manual switching actions that were taken. The inspectors also reviewed switchyard and plant equipment response during restoration activities. The inspectors participated in the discussions and performed the reviews to verify that plant and switchyard equipment responded as expected during the event.

b. Findings

No findings of significance were identified.

.6 Licensee Oversight of Switchyard Activities

a. Inspection Scope

The inspectors reviewed the licensee's control and oversight of maintenance, switching, and recovery activities in the switchyard. Specifically, the inspectors reviewed the following items: (1) historical switchyard maintenance and switching problems to assess the effectiveness of previously identified corrective actions; (2) adequacy of licensee oversight over maintenance activities occurring in the switchyard prior to and during the events of June 12, 2002; (3) corrective maintenance being performed and planned for replacement of the "M1" breaker in the D. C. Cook switchyard; and (4) the interface between D. C. Cook control room staff and AEP power distribution personnel.

b. Findings

The results of the inspectors' reviews are documented below. No findings of significance were identified.

b.1 Historical Switchyard Maintenance and Switching Problems

The inspectors reviewed historical switchyard problems to determine if an adverse trend in the control of switchyard activities existed and to assess the effectiveness of licensee corrective actions. The inspectors noted that there have been several significant switchyard events associated with maintenance and oversight activities and that several events have been attributed to inadequate oversight of AEP electrical distribution personnel as noted below:

- May 24, 1990: 345 kV switchyard breaker "L" phase 2 current transformer catastrophically failed (CR 90-0775). The failure of the "L" breaker current transformer damaged the "K1" Unit 1 main generator output breaker and resulted in an Alert declaration under the licensee's emergency plan. The licensee determined that the failure was likely caused by internal support damage to the current transformer during shipping or installation. Because the licensee determined that this was an isolated event, corrective actions were limited to repairing the "L" breaker.

- August 1, 1991: Unit 2 tripped due to catastrophic failure of the phase 3 current transformer on the main generator output breaker "A1" (LER 50-316/91-006-00). The licensee determined that the most likely cause of the failure was internal insulation deterioration. The licensee also determined at that time, that the failure to perform preventive maintenance on some of the switchyard equipment in accordance with “published guidelines” may have contributed to not discovering the degraded condition. Corrective actions included transferring the responsibility for predictive and preventive maintenance scheduling related to switchyard current transformer deterioration to the AEP nuclear generation organization. The inspectors noted that Section 7.3.1 of the Inter Organizational Agreement between Cook Nuclear Plant and the AEP electrical distribution organization stated that the Cook Nuclear Plant offsite power system manager was responsible for ensuring that maintenance guidelines met applicable requirements.

- December 16, 1999: Inappropriate maintenance activity resulted in loss of the Unit 2 Train “A” reserve feed transformer (LER 50-315/99-028-00, CR 99-29277). The licensee determined that the root cause for this event was a failure to take effective corrective actions following previous switchyard events. Corrective actions for this event included control of switchyard access by the operations shift supervisor and revision to the AEP interface agreement for D. C. Cook switchyard activities. The intent of these corrective actions was to place additional controls on switchyard maintenance activities.

- June 8, 2000: Manual switching error resulted in loss of the “A” train reserve feed supply to both units (LER 50-316/2000-004-00, CR 00-8384). The licensee determined that the root cause for this event was inadequate control of manual switchyard switching operations. Corrective actions included revising the AEP interface agreement for D. C. Cook switchyard activities to require concurrent verification of switching operations in the switchyard.

- April 25, 2002: Insulator on disconnect for the Unit 1 main generator output breaker “K1" damaged during maintenance activities. This event resulted in a greater than 20 percent power reduction to support removal of the Unit 1 main generator from service in order to secure the damaged disconnect. Immediate corrective actions required continuous Cook Nuclear Plant oversight for all critical tasks (defined as any task that a single action could affect unit operation, a unit power output, or a reserve feed source that supplies Cook plant) in the switchyard.

The inspectors concluded the licensee had narrowly focused previous corrective actions pertaining to switchyard oversight activities to each specific event, rather than considering a comprehensive review of switchyard activities. For example, although the December 1999 and June 2000 problems both involved improper switchyard activities by AEP electrical distribution personnel, corrective actions did not include continuous Cook Nuclear Plant oversight of work activities until after the April 25, 2002, event. The inspectors also concluded that since the April 2002 event, the licensee has enacted an appropriate level of oversight for switchyard maintenance and switching activities.

b.2 <u>Adequacy of Licensee Oversight of Switchyard Activities</u>

On June 12, 2002, prior to the failure of the “L” breaker phase 1 current transformer, there were two maintenance groups working in the D. C. Cook switchyard performing critical maintenance tasks (associated with replacement of the “M1” breaker) who were assigned a D. C. Cook Nuclear Plant electrical maintenance liaison. The inspectors reviewed the scope and location of maintenance activities and determined that the level of oversight for switchyard activities prior to the event was adequate. Additionally, the inspectors did not identify any evidence that switchyard maintenance activities caused or contributed to the failure of the “L” breaker.

Following the catastrophic failure of the “L” breaker current transformer, AEP electrical power distribution personnel performed manual switching operations which resulted in a loss of Train “B” preferred offsite power source to both units and an unsuccessful attempt to open the Unit 1 main generator output breaker. The inspectors reviewed these switching operations and concluded that the manual switching actions were reasonable and appropriate for the circumstances. The switching actions following the June 12, 2002 event were performed with the concurrence of the responsible AEP load dispatcher and were consistent with proceduralized guidance contained in Section 6.6, “Emergency Operations,” of the inter-organization agreement between AEP nuclear generation and electrical distribution groups for emergency switchyard actions during an immediate threat to personnel safety.

b.3 Interface Between D. C. Cook Control Staff and AEP Power Distribution Personnel

The inspectors reviewed AEP load dispatcher logs, control room logs, and discussed the events immediately following the “L” breaker failure with AEP electrical distribution and Cook Nuclear Plant personnel to assess the effectiveness of communication between the D. C. Cook control rooms and AEP electrical power distribution personnel. The inspectors noted that the control rooms were promptly informed of the switchyard explosion and fire. However, the inspectors noted that the control room was not informed prior to the attempted opening of the Unit 1 Main Generator Output “K” Breaker and the load dispatcher did not immediately notify the control room following isolation of the preferred offsite power supply. Although the inspectors concluded that the failure to promptly communicate manual switchyard breaker operations to the control room may have hampered the operators’ early evaluation and diagnosis of the event, the inspectors concluded that the level of communication was consistent with proceduralized guidance for emergency switchyard activities during an immediate threat to personnel safety.

.7 Licensee’s Emergency Plan Response Action to the Incident

a. Inspection Scope

The inspectors reviewed logs from the Technical Support Center (TSC), Operations Support Center (OSC), Emergency Operations Facility (EOF) and the control room to verify that emergency response actions were completed in accordance with the applicable emergency plan implementing procedure requirements. The inspectors also reviewed the basis for the emergency being classified as an Alert and the notifications that were communicated to offsite authorities to verify that they were accurate and timely.

b. Findings

The results of the inspectors' reviews are documented below. No findings of significance were identified.

b.1 Emergency Plan Implementation Including Offsite Fire Response Personnel

Emergency Declaration and Notification

The inspectors determined that the Alert declaration was accurate and completed in a timely manner and that the emergency response facilities were manned in a timely manner with the appropriate number of emergency responders. Although the inspectors also determined that the initial offsite notification was timely, the initial offsite notification was not accurate in that the atmospheric conditions regarding wind direction had the "to" and "from" directions reversed. However, there were no radiological releases in progress or imminent during the event, and, therefore, no adverse impact on event response resulted from the inaccurate wind directions. Also, during discussions with licensee emergency preparedness personnel, the inspectors determined that the issue was intended to be appropriately captured in the performance indicator data for Emergency Response Organization Drill/Exercise Performance as a "missed opportunity." The inspectors also noted that this issue had been identified during the event by licensee emergency response personnel in the Technical Support Center who had logged that the wind direction on the initial notification form was not accurate. All subsequent notifications to offsite authorities were accurate.

Initial Notification to Emergency Response Personnel

The inspectors noted one issue regarding the licensee's response to the Alert emergency condition. Following the declared Alert, security personnel paged emergency response personnel using a code which represented a security event vice a plant event. During a security event, emergency responders who are not on site are to report to an offsite facility. Therefore, had this event occurred during off-normal business hours, the use of the security event code could have adversely impacted the licensee's ability to man the onsite emergency facilities in a timely manner. Consequently onsite technical assistance and resources to assist the control room in mitigating the event could have been adversely impacted.

However, the Alert was fortuitously declared during normal business hours and enough emergency responders were available on site to activate the emergency facilities and provide technical assistance and resources to the control room to assist in mitigating the event. The inspectors concluded that this issue was minor in that there was no impact on the licensee's ability to complete required emergency plan actions. Therefore, although this issue should be corrected, it constitutes a violation of minor significance that is not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy.

During follow-up discussions with licensee personnel, the inspectors noted that security personnel responsible for paging emergency response personnel did not have the correct authorization number to transmit a plant event code. Instead, primary station security personnel only had authorization numbers to transmit a page using the security event code. Licensee personnel subsequently identified that the correct authorization numbers were also not provided at the back up security station. Consequently the back up site would not have been able to page emergency response personnel for either a security event or a plant event.

Licensee personnel initiated Condition Report CR 02164053, “Wrong Code Entered For ERO Page Out,” which was entered into the corrective action program to evaluate this issue. Also, when these problems were identified, licensee emergency preparedness personnel promptly provided the correct authorization numbers for paging emergency response personnel if necessary.

Communications During the Alert

The inspectors noted several communication weaknesses during the response to the Alert. Most significantly, one D. C. Cook Nuclear Plant employee who had responded to the switchyard after the initial explosion made the decision to turn away the offsite fire department that responded to the site. That decision was based on discussions with AEP Transmission and Distribution personnel in the switchyard who had recommended to let the fire burn out by itself. However, the decision to turn away the fire department did not go through the Shift Manager who was in charge of event response at the time. Consequently, during the initial response activities, the Shift Manager was unaware that the offsite fire department was not available to assist in fire fighting activities if needed.

The inspectors concluded that, while the decision to turn away the offsite fire department that responded to the site should have been made by the Shift Manager, there was no resultant significant adverse impact by turning away the offsite fire department. The fire was contained and the onsite fire brigade was at the switchyard if needed. However, the offsite fire department would have been a readily available valuable fire fighting resource if the situation had gotten worse.

b.2 Operations Staff Response

No findings of significance were identified.

4OA5 Other Activities

a. Inspection Scope

The inspectors reviewed the circumstances associated with the issuance of a Notice of Enforcement Discretion (NOED) to allow an extension to the allowed outage time for TS 3.0.5. The inspectors reviewed the cause of the licensee's entry into the TS 3.0.5 Limiting Condition for Operation on June 12, 2002, the basis for the licensee's NOED request, and the licensee's compliance with the compensatory actions of the NOED.

b. Findings

(Closed) Unresolved Item 50-315,50-316/02-07-02: "Review of NOED-02-3-02 Regarding D. C. Cook, Units 1 and 2, Compliance With TS 3.0.5"

No findings of significance were identified during the inspectors' review of the root cause of the licensee's entry into TS 3.0.5, the basis of the NOED request, and the licensee's implementation of the NOED required compensatory actions.

The inspectors reviewed the licensee's NOED request to assess the qualitative and quantitative basis for the extension to the TS 3.0.5 allowed outage time. In their verbal NOED request on June 12, 2002, the licensee stated that, due to the degraded preferred offsite power condition, continued stable power operation with appropriate compensatory measures, provided a net risk benefit compared to compliance with the shutdown actions required by TS 3.0.5. Additionally, the licensee stated in their June 14, 2002, follow-up letter (AEP: NRC:2016-02), that in the degraded switchyard condition that existed, taking the units off line would change the electrical load flow patterns on the grid and would increase the probability of grid instability and the likelihood of a loss of offsite power.

At the time that the NOED was granted, only one offsite connection to the switchyard was available to supply preferred offsite power to both units following a unit shutdown or trip. Loss of the preferred offsite power supply following a unit trip or shutdown would have resulted in loss of the reactor coolant and circulating water pumps and necessitated the use of natural circulation decay heat removal. The inspectors concluded that the basis for the licensee's NOED request was adequately supported. Additionally, the inspectors reviewed the licensee's compensatory actions and determined that the actions were reasonable and appropriately implemented.

The inspectors also reviewed the circumstances associated with the licensee's NOED request to determine if a failure to comply with regulatory requirements contributed to the need for enforcement discretion. The inspectors concluded that, had the Unit 2 East ESW pump not been removed from service for a planned pump replacement, the licensee would not have required an entry into TS 3.0.5. The loss of the preferred offsite power supply, with no other TS equipment out of service, would have resulted in the entry into TS 3.8.1.1 for electrical power sources with an associated 72 hour allowed outage time, rather than the 2 hour allowed outage time per TS 3.0.5. Based on the licensee's prompt actions to recover the switchyard capability, the inspectors concluded that the licensee would not have required an NOED to recover the preferred offsite power supply within 72 hours of the failure of the "L" breaker. Consequently, the inspectors concluded that the NOED was necessitated by the coincidental performance of pre-planned maintenance on the Unit 2 East ESW pump during the event; therefore, the entry into TS 3.0.5 was not due to a failure to comply with regulatory requirements.

The inspectors opened URI 50-315, 50-316/02-07-02(DRP) to track documentation of the root cause for the NOED request, NOED approval basis, and verification activities. Because, the root cause for the NOED request and the approval basis was reviewed and considered reasonable, this URI is closed.

4OA6 Exit Meeting

The inspectors presented the inspection results to Mr. J. Pollock and other members of licensee management and staff on June 27, 2002. The inspectors asked whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

KEY POINTS OF CONTACT

Licensee

C. Bakken, Senior Vice President, Nuclear Generation
R. Gaston, Regulatory Compliance Manager
C. Graffenius, Emergency Plan Coordinator
S. Greenlee, Director, Nuclear Technical Services
N. Guntz, Engineer 3, AEP Transmission and Distribution
H. Torberg, Security Supervisor
P. Holland, Emergency Preparations Services Manager
E. Larson, Director, Operations
R. Meister, Regulatory Affairs
J. Molden, Equipment Reliability Director
C. Moore, Ft. Wayne Transmission and Distribution Supervisor
J. Piazza, Plant Protection Manager
J. Pollock, Site Vice President
S. Stewart, Electrical Maintenance
T. Szymanski, System Manager
L. Weber, Performance Assurance Supervisor

NRC

D. Passehl, Acting Chief, Reactor Projects Branch 6
S. Burgess, Senior Reactor Analyst, RIII
R. Jickling, Emergency Planning Inspector, RIII

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-315-02-07-01 50-316-02-07-01	FIN	Failure to Perform Switchyard Current Transformer Preventive Maintenance in Accordance with Vendor Recommendations
50-315-02-07-02 50-316-02-07-02	URI	Review of NOED-02-3-02 Regarding D. C. Cook, Units 1 and 2, Compliance With TS 3.0.5

Closed

50-315-02-07-01 50-316-02-07-01	FIN	Failure to Perform Switchyard Current Transformer Preventive Maintenance in Accordance with Vendor Recommendations
50-315-02-07-02 50-316-02-07-02	URI	Review of NOED-02-3-02 Regarding D. C. Cook, Units 1 and 2, Compliance With TS 3.0.5

Discussed

None

LIST OF DOCUMENTS REVIEWED

4OA3 Event Followup

Plant Procedures

01 OHP 4022.082.004	Degraded Offsite AC Voltage Response	Revision 1
AEP Standard Operating Procedure (SOP) #10	Cook Nuclear Plant Transmission/Auxiliary Voltage operating Guide	Revision 4
Post Order SPO.051	Emergency Response Organization (ERO) Pager Activation (Dialogic)	Revision 5
EPAM-2001-002	ERO Pager Testing and Maintenance	Revision 0
PMP-2080-EPP-107	Notification	Revision 15a
PMP-2080.EPP.101	Emergency Classification	Revision 3b
PMP-2080-EPP-100	Emergency Response	Revision 0
EPAM-2001-001	Emergency Plan Administrative Manual	Revision 5
RMT-2080-EOF-001	Activation and Operation of the EOF	Revision 1
RMT-2080-OSC-001	Activation and Operation of the OSC	Revision 0
RMT-2080-EOF-002	Emergency Termination and Recovery	Revision 0
RMT-2080-TSC-001	Activation and Operation of the TSC	Revision 0

Condition Reports

CR 12-05-90-0775	Breaker Explosion and Fire in the 345 kV Switchyard. CD Reserve Power Transformer Deluge Actuated.	May 24, 1990
CR 00-10172	Testing in the switchyard is performed without procedures and without peer checks	July 19, 2000
CR 00-8384	Loss of “A” train reserve feed due to switching error in the switchyard	June 8, 2000
CR 01129109	Failure of Cook Load Flow Program	May 9, 2001
CR 02115039	Insulator disconnect damaged on Unit 1 main generator output breaker K1 due to maintenance error	April 25, 2002

CR 02163040	Unit 1 L-1 Current Transformer failed causing a fire and spill of greater than 5 gallons but less than 230 gallons of transformer oil to the ground.	June 12, 2002
CR 02163045	1-52-L has had a catastrophic failure, resulting in a loss of Offsite Power Sources supplied to Reserve Feed. Both units have entered Tech Spec 3.8.1.1 and Tech Spec 3.0.5.	June 12, 2002
CR 02165043	Entered action statement for inoperable offsite power sources. Control room unable to contact load dispatcher using unit supervisor direct line	June 14, 2002
CR 02165060	Load tap changer Control did not reduce 4kV potential to the required 199 secondary volts. Output voltage is at 123 Volts	June 14, 2002
CR 02168002	Operator and engineering training for DCP 4504 Reserve Feed Auxiliary transformers was insufficient to meet operator needs	June 16, 2002
CR 90-0775	Breaker explosion and fire in 345 kV switchyard	May 24, 1990
CR 99-18866	St. Joe Division electrical work practices appear not to align with Cook Plant work practices	July 19, 1999
CR 99-20153	Lack of control, interface, and method of tracking maintenance work performed by outside organizations	August 3, 1999
CR 99-29277	Sudden pressure trip on reserve feed transformer 201CD due to maintenance error resulted in loss of Unit 2 preferred offsite power supply	December 16, 1999
CR 99-29312	Stop work order issued for all St. Joseph Division work which can impact essential offsite power	December 17, 1999
CR 02164053	Wrong Code Entered for ERO Page Out	June 12, 2002

Job Orders

JO R0019480	Perform 1-52-L External Inspection	April 25, 1997
JO R0020235	Test/DGA 1-52-L and 1-TR-L-CT1/2/3	June 6, 1994
JO R0031722	Test/DGA 1-52-L and 1-TR-L-CT1/2/3	September 28, 1998
JO R0057632	Perform 1-52-L External Inspection and Breaker Timing	October 11, 2000
JO 02031035	Clean/Inspect 1-152-M-TB2 north phase disconnect	June 13, 2002
JO R0208872	Check Heaters at Breaker 1-52-L	August 3, 2001
JO R0209953	Operational Trip Check 1-52-L	August 22, 2001

Licensee Event Reports

LER 50-315/1999-021	Electrical Bus Degraded Voltage Too Low for Safety Related Loads	March 23, 2000
LER 50-315/99-028	ESF Actuation and Start of Emergency Diesel Generator 1CD During Transformer Maintenance	January 17, 2000
LER 50-316/2000-004	Partial Loss of Offsite Power Results in Start of Emergency Diesel Generators	July 7, 2000
LER 50-316/91-006	Reactor Trip - Turbine Trip from Main Generator Protective Relay Operation During Failure of a Main Generator Output Breaker Current Transformer	August 30, 1991

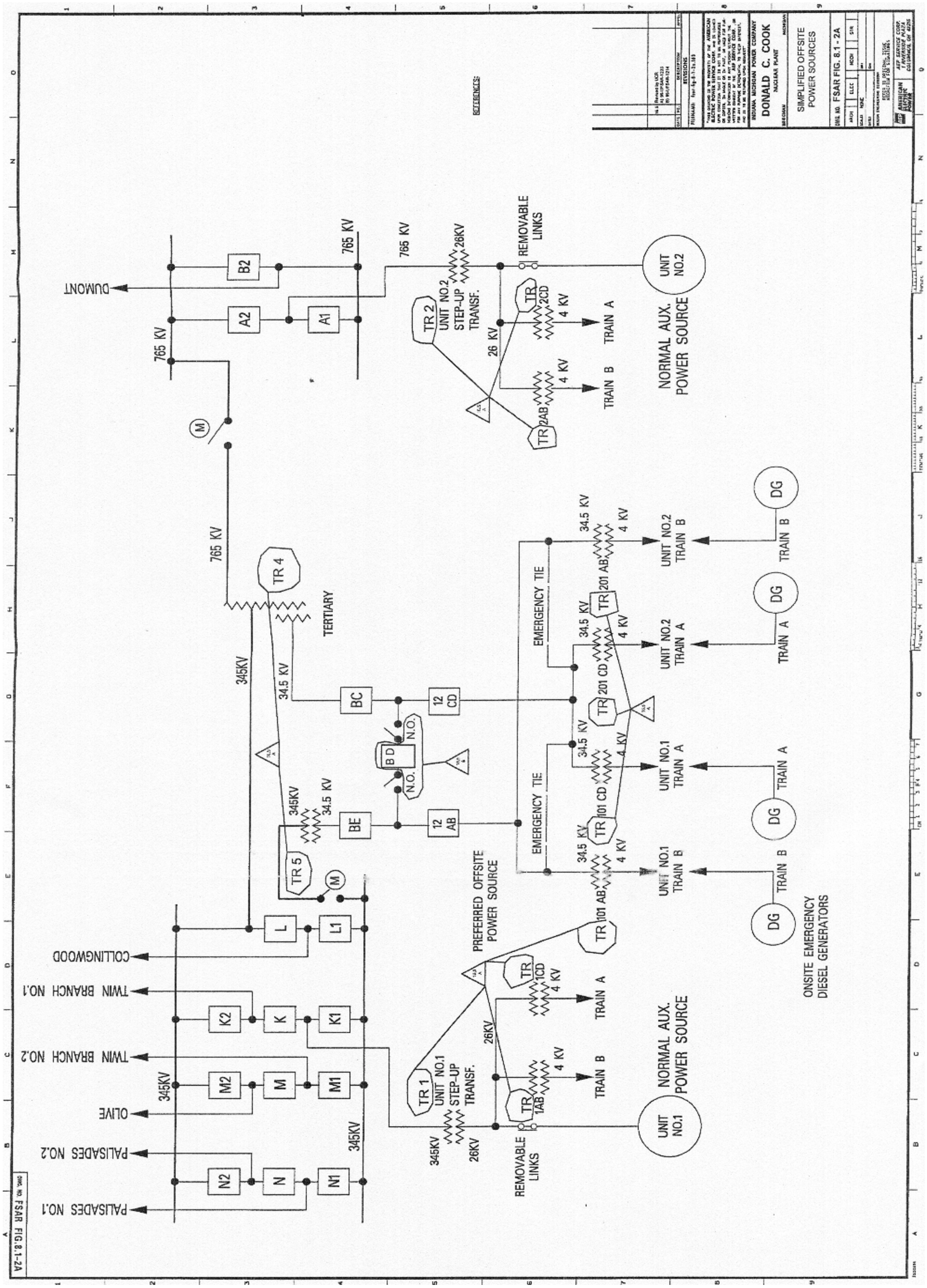
Miscellaneous Documents

	Unit 1 and Unit 2 control room power log reports, and the Shift Manager power log report	June 12, 2002
	CR02163045, 345 kV Breaker L Failure, root cause evaluation team charter	June 12, 2002
	Technical Support Center, Operational Support Center and Emergency Operations Facility logs	June 12, 2002
	Completed Nuclear Plant Event Notification forms	June 12, 2002

	Written statements completed by AEP Transmission and Distribution personnel, and Cook Nuclear Plant personnel who were in the switchyard and responded to the switchyard during the event.	
	Michigan State Police Communicator logs	June 12, 2002
	Fort Wayne Daily Operating Report Logs	June 12-13, 2002
	Inter Organization Agreement Between the AEP Energy Delivery and Customer Relations Group and the AEP Nuclear Generation Group for Assistance to Cook nuclear Plant	August 7, 2001
	Maintenance Rule Scoping Document Offsite Power System	Revision 2, October 24, 2001
	NRC Inspection Report Nos. 50-315/90010(DRP); 50-316/90010 (DRP)	June 18, 1990
1-DCP-4504	Replace Auxiliary Transformers 101AB and 101CD with Load Tap Changing Transformers	
	AEP System Guidelines for T&D Maintenance Frequencies- Circuit Breakers	April 8,1999
1Q2002	System Health Report -- Offsite Power	For first quarter 2002 (no date)
AEP Letter to Mr. J. G. Reckleff from Mr. J. L. Schnegg / B. A. Burke	345 Current Transformer Failure at D. C. Cook Station	June 22, 1990
AEP Letter to Mr. Thomas A. Szymanski from Mr. Michael D. Higgins and Mr. Mark A. Bailey	Letter describing AEP’s analysis of the recent failure in the switchyard at the D. C. Cook plant.	June 21, 2002
Instruction Book Z 12826-1	For Alsthon Savoisienne Current Transformer Type IHC 145/12 and IHC 345/12	December 5, 1970
	D. C. Cook Nuclear Plant Emergency Plan	Revision 17

4OA5 Other

Letter AEP:NRC:2016-02	Request for Notice of Enforcement Discretion from Limiting Condition for Operation 3.0.5 Regarding Essential Service Water Pump Operability	June 14, 2002
NRC Letter to Mr. A. C. Bakken	Notice of Enforcement Discretion for Indiana and Michigan Power Company Regarding D. C. Cook, Units 1 and 2 (NOED-02-3-002)	June 18, 2002



PALISADES NO.1
PALISADES NO.2
OLIVE
TWIN BRANCH NO.2
TWIN BRANCH NO.1
COLLINGWOOD
DUMONT
345KV
765 KV
N2
N
N1
M2
M
M1
K2
K
K1
L
L1
A2
A1
B2
TR 1
UNIT NO.1
STEP-UP
TRANSF.
26KV
TR 2
UNIT NO.2
STEP-UP
TRANSF.
26 KV
TR 4
TERTIARY
TR 5
34.5 KV
BC
BE
12 CD
12 AB
B D
N.O.
PREFERRED OFFSITE
POWER SOURCE
EMERGENCY TIE
TR 1AB
TR 1CD
TR 2AB
TR 2CD
TR 101 AB
TR 101 CD
TR 201 CD
TR 201 AB
4 KV
TRAIN A
TRAIN B
REMOVABLE
LINKS
UNIT
NO.1
UNIT
NO.2
NORMAL AUX.
POWER SOURCE
UNIT NO.1
TRAIN A
UNIT NO.1
TRAIN B
UNIT NO.2
TRAIN A
UNIT NO.2
TRAIN B
DG
ONSITE EMERGENCY
DIESEL GENERATORS
REFERENCES:
INDIANA MICHIGAN POWER COMPANY
DONALD C. COOK
NUCLEAR PLANT
SIMPLIFIED OFFSITE
POWER SOURCES
DWG NO. FSAR FIG. 8.1-2A