U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket/Report No.	50-277/92-14 50-278/92-14	License Nos. DPR-44 DPR-56
Licensee:	Philadelphia Electric Company Peach Bottom Atomic Power Station P. O. Box 195 Wayne, PA 19087-0195	
Facility Name:	Peach Bottom Atomic Power Station Units 2 and 3	
Dates:	July 4 - July 11, 1992	
Inspectors:	M. G. Evans, Acting Senior Resident Inspector F. P. Bonnett, Resident Inspector F. J. Laughlin, Emergency Preparedness Specialist J. H. Lusher, Emergency Preparedness Specialist R. K. Mathew, Reactor Engineer	

Approved By: J. J. Lyash, Acting Chief, Reactor Projects Section 2B, Division of Reactor Projects — Date: 7/20/92

Areas Inspected:

This Special Inspection included a review of the circumstances surrounding the declaration of an Alert on July 4, 1992, following the failure of the 'B' phase of the No. 1 auto transformer and the No. 173 disconnect switch in the North Substation of the Peach Bottom Atomic Power Station. Inspector review focused on the failure of the transformer and disconnect switch, the failure of the E13 emergency bus to automatically transfer to the second off-site power source, operational issues involving the Unit 3 automatic reactor scram, and issues related to emergency planning.

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EXECUTIVE SUMMARY

Peach Bottom Atomic Power Station
Inspection Report 92-14

This Special Inspection was conducted to review the events surrounding the declaration of an Alert on July 4, 1992, following the loss of one of two off-site power sources due to the failure of an auto transformer and disconnect switch in the North Substation; the loss of power to one 4 Kv emergency bus due to the failure of a breaker control switch; and a Unit 3 reactor scram due to low condenser vacuum. The inspectors concluded that the actual safety significance of the event was low. However, the coincident failures that caused loss of one offsite power source, and de-energization of one safety-related 4 kV bus must be viewed as an important event precursor.

Overall, the inspectors concluded that the licensee had appropriately evaluated all issues, specifically those related to the availability of the off-site power source and the loss of power to the emergency bus. The inspectors found the licensee's immediate and interim corrective actions related to the failures of the transformer, the disconnect switch, and the breaker control switch to be acceptable. In addition, the licensee has committed to complete the root cause analyses of the failures in the substation by August 21, 1992 (Unresolved Item 50-278/92-14-01, Section 3.1) and of the failure of the control switch by July 25, 1992 (Unresolved Item 50-278/92-14-02, Section 3.2).

The inspectors also concluded that the licensee's operational and emergency planning response to the event were appropriate. Station management took an active role and demonstrated a strong safety focus in the review and resolution of all issues. The engineering staff was knowledgeable and provided good support for analysis and resolution of the issues and for this inspection. Good communication existed between the Transmission and Distribution Department and the plant to address the substation issues.

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DETAILS

1.0 BACKGROUND

Simplified diagrams of the power distribution system for the Peach Bottom Atomic Power Station (PBAPS) are presented in Attachment 'A'. PBAPS Units 2 and 3 Technical Specification 3.9.A.1 requires that two independent power sources from the off-site transmission network to the on-site Class 1E distribution system be operable. The No. 3 startup regulating transformer switchgear is powered from one off-site source, the Newlinville Line (220-34), through either 13.2 kV startup transformer No. 343 or the startup and emergency auxiliary regulating transformer No. 3. The No. 2 startup transformer switchgear is powered from the second off-site power source, the Graceton-Nottingham line (220-08), through 13.2 kV startup and emergency auxiliary transformer No. 2. The two off-site sources are connected to the on-site Class 1E distribution system by physically independent circuits. In addition, four emergency diesel generators (EDG) are available to supply power to the Class 1E distribution system if the off-site sources become unavailable. In the normal mode of operation for each unit, two of the Class 1E buses are powered from the No. 2 startup transformer switchgear and two buses from the No. 3 startup regulating transformer switchgear. If one source of off-site power is lost, the respective incoming breakers open and transfer to the remaining off-site power source. If the second offsite source is not available, the diesel generators start automatically and supply power to the loads.

The Newlinville line is also tied to Muddy Run Pump Storage Station lines (220-06 and 220-07) and the North Substation 500 kV ring bus through the No. 1 auto transformer. During periods of high system loading on the transmission network, Muddy Run reservoir is used as a power source by running as many as eight pumps as hydroturbine generators. At night when system loading is low, power from the No. 1 auto transformer and the Newlinville line is supplied to Muddy Run to pump water back into the reservoir.

On the morning of July 4, 1992, five pumps at Muddy Run were being powered from the No. 1 auto transformer to pump water back into the reservoir. The Newlinville line was supplying power to the No. 3 startup regulating transformer switchgear through the No. 343 startup transformer.

2.0 EVENT SUMMARY

At 1:50 a.m. on July 4, 1992, the licensee declared an Alert due to the reported explosion of the 'B' phase of the No. 1 auto transformer in the North Substation, about one mile from the plant. Units 2 and 3 were operating at about 95% power at the time of the event. The failure of the transformer combined with the opening of the No. 343 startup transformer 13 kV output breaker (Breaker No. 3435) resulted in the loss of one of two offsite power sources for Peach Bottom. The loss of offsite power to the No. 3 startup regulating transformer switchgear resulted in multiple 4 kV emergency bus automatic transfers (auto-transfers) to the second offsite power source through the No. 2 startup transformer switchgear. Three of the four safety-related 4 kV buses successfully transferred. The E13 bus did not auto-transfer, which resulted in a loss of power to the bus. Operators manually transferred the E13 bus to the second off-site power source, however, temporary loss of power to the bus caused the isolation of the offgas system for Unit 3. This resulted in a loss of condenser vacuum and an automatic Unit 3 reactor scram. All systems responded as expected, and the operators completed a normal reactor cooldown.

Unit 2 remained at about 95% power throughout the event. As a result of a momentary loss of power to 120 vac panels 20Y34 and 20Y35 during the 4 kV auto-transfer, the Unit 2 reactor water cleanup (RWCU) and shutdown cooling (SDC) systems isolated. In addition, the extraction steam to the '3B' and '4B' feedwater heaters isolated, causing a slight positive reactivity insertion. The reactor operator (RO) took appropriate actions to reduce reactor power per procedure Operational Transient (OT) 104, "Positive Reactivity Insertion." Power was reduced to about 91%. The RO reset the isolations within a few minutes and the Unit was returned to 95% power. The RWCU and SDC isolations are emergency safeguard feature (ESF) actuations which the licensee reported to the NRC via the Emergency Notification System (ENS). The licensee also reported the Alert, the Unit 3 reactor scram and the associated ESF actuations to the NRC via the ENS. The inspector reviewed the licensee's response to the Unit 2 isolations and found their actions to be acceptable. Based upon the minimal effect of this transient on the operation of Unit 2, no additional inspection for Unit 2 was performed.

A chronology of the events related to this incident, specifically for Unit 3, is listed below (times are approximate):

July 4, 1992

0100	Unit 2 and 3 both operating at about 95% power.
01[illegible]	Outside Coordinator (OC) reports to the control room that there is arcing and light at the North Substation. OC is dispatched to investigate.
0117	Breakers 65, 75, 175, 345 and 675 open due to a sensed phase to phase fault. Breakers 175, 345 and 675 reclose as designed.
0118	OC reports a fire in the North Substation.
0119	A phase to ground fault is sensed and 500 kV breakers 35 and 45 open. Also, circuit breaker 175, 675 and 3435 open causing the loss of the No. 3 startup regulating transformer switchgear. Units 2 and 3 emergency bus auto-transfers occur. E13 bus does not auto-transfer and the E-1 EDG does not start. Numerous Unit 3 alarms are received in the control room including the 'A' Reactor Protection System (RPS) channel half scram. Condenser vacuum begins to decrease and the Unit 3 RO enters OT 106, "Loss of Condenser Vacuum."

0126	The chief reactor operator (CRO) manually restores power to the E13 emergency bus.
0127	Unit 3 reactor scram occurs as a result of low condenser vacuum.
0140	Shift Supervisor (SSV) receives a report from the OC of an explosion in the North Substation.
0150	Shift Manager (SM) declares an Alert and assumes duties as Emergency Director (ED).
0202	Initial notifications complete.
0220	Operations Support Center (OSC) is activated.
0225	Emergency Response Organization (ERO) pagers are activated.
0241	NRC is notified via FTS-2000. The Emergency Response Data System (ERDS) is activated.
0245	Personnel begin arriving at the Technical Support Center (TSC).
0300	TSC activation is started.
0315	Operations Superintendent arrives at TSC and attempts to contact the ED for turnover.
0325	Operations Superintendent contacts ED for turnover.
0340	Operations Superintendent turnover from the ED is complete. Operations Superintendent briefs TSC personnel.
0345	ED declares TSC activated.
0350	Operations Superintendent assumes ED duties in the TSC.
0355	Pennsylvania Emergency Management Agency called TSC for status update.
0401	ED contacts SM to begin going through recovery checklist.
0417	Conference call among the ED, SM and the Emergency Response Manager (ERM) to go through recovery checklist. Recovery entry

delayed pending determination of the reason for the failure of the E13 bus to auto-transfer.

0515 CRO closes circuit breaker 3435 and restores off-site power to the No. 3 startup regulating transformer switchgear.

0524 ED provides status update to NRC via FTS-2000.

0605 ED declares termination of the Alert and event recovery phase is entered.

0615 Notification of off-site agencies initiated from TSC.

0621 Off-site notifications of Alert termination complete.

The NRC dispatched two Resident Inspectors to the site, manned the Region I Incident Response Center, and placed the agency in the Monitoring Mode.

3.0 INSPECTOR FOLLOW-UP

The inspector's follow-up review focused on the transformer and disconnect switch failure, the E13 bus failure to auto-transfer, operational issues involving the Unit 3 reactor scram and the licensee's post-scram review, and emergency planning issues. Inspector follow-up for each of these issues is discussed in detail below.

3.1 Transformer and Disconnect Switch Failures

Shortly after the event on July 4, licensee personnel visually inspected the breakers and power lines in the North Substation for any traces of fault conditions. The licensee found that the damaged components were the 'B' phase of the No. 1 auto transformer and the No. 173 disconnect switch for the No. 1 auto transformer. The licensee appropriately tagged the No. 175 breaker and No. 173 disconnect switch to assure their removal from service and reclosed the 3435 breaker to re-establish off-site power to the No. 3 startup regulating transformer switchgear.

During this inspection, the inspector performed a walkdown of the substation and control room, interviewed licensee personnel, and reviewed component design, operation, and maintenance to understand the cause of the failure of the transformer and the disconnect switch. The transformer was manufactured by Canadian General Electric with the following rating: 3-373.33 MVA-512.5, 230.6 and 14.4 kV, OA/FA/FOA, HV-BIL-1550 kV and LV-BIL-825 kV. The disconnect switch was manufactured by H.K. Porter and had the following data: MK-40, 230 kV, 2000 A, 100,000 momentary amperes, 900 kV BIL, Cat. No. U1-06598X86. The No. 1 auto transformer had originally been placed in service in 1986, following the failure of the previous

No. 1 auto transformer. This failure also resulted in the loss of power to the No. 3 startup regulating transformer switchgear, due to the loss of control circuitry in a fire. The licensee stated that the root cause of the previous No. 1 auto transformer fault could not be determined because of the severity of the damage due to the fire.

The inspector reviewed the licensee's sequence of events, digital fault recorder data and load dispatcher and operator logs. This information indicated that the protective relays for the Muddy Run 220-06 and 07 lines saw the initial fault and isolated line breakers 65 and 75 and North Substation breakers 175, 345 and 675. These breakers were reclosed by the line protective relays due to the reclosure feature for clearing small line faults. The digital fault recorder indicated that the initial fault was a phase to phase fault on the 'B' and 'C' phases of the 230 kV system. After the reclosure, the fault developed into a phase to ground fault, causing the No.1 auto transformer to contribute to the fault and resulting in the failure of the 'B' phase of the transformer. Visual inspection of the transformer revealed that the top cover had lifted and transformer oil had spilled due to the sudden pressure developed in the transformer caused by the fault. However, the fault did not cause any fire in the substation and the spilled oil was contained within the transformer moat. During the event, the transformer primary and backup differential relays were activated and locked out 230 kV breakers No. 175 and 675 and 500 kV breakers 35 and 45. The inspector noted that following the event and pending final determination of the cause of the failures, the licensee blocked the reclosure feature for breakers 675 and 345 to prevent reclosure during any future line fault.

During the event, the Newlinville off-site power source to the plant was lost due to the trip of the No. 3435 breaker. The inspector noted that there was no automatic tripping of the breaker as indicated by the lack of any relay targets. The licensee initially suspected that the breaker actuation was caused by actuation of an under-frequency relay, although the relay target was not up. The licensee verified relay settings and calibrations and assured that the relays were operating accurately. The duration of the faults were observed as 4 cycles and the relay settings were found to be 58.5 Hz with a time delay of 6 cycles. Therefore, the under-frequency relays did not actuate. The licensee could not determine the cause of the 3435 breaker trip. However, based on breaker functional testing and relay calibrations, they concluded that breaker 3435 was operable and could be returned to normal service.

During review of maintenance activities in the substation, the inspector noted that the licensee had previously identified a hot spot on the 'B' phase of the No. 173 disconnect switch. The hot spot was found to be on the 'B' phase clipper end of the disconnect switch with a temperature of 48 degrees C. This was identified on May 22, 1992, during a routine Transmission and Distribution (T&D) thermography survey. The thermography survey procedure indicated that when the total hot spot temperature was above 120 degrees C, immediate corrective action was required to relieve the hot spot problem. The licensee stated that for the observed condition, the hot spot would be periodically monitored to verify the condition of the disconnect switch until the problem was corrected. The inspector noted that the plant personnel had previously performed thermography and had identified problems with the 'C' phase of the disconnect switch. However, this hot spot had cleared before the May T&D thermography. The inspector verified that the licensee's T&D group performed the thermography three times a year and that appropriate corrective actions had been taken for any hot spot conditions. During the walkdown of the substation, the inspector observed that the hinge side of the 'B' phase disconnect switch was badly damaged with melted connections and shattered insulators. Even though the damage was on the hinge side of the disconnect switch, the inspector questioned the licensee regarding whether the prior hot spot condition on the clipper side of the disconnect switch may have contributed to the initial fault on the 230 kV system. The licensee stated that they did not believe it had, but further evaluation was necessary to confirm the results.

A review of the licensee's maintenance on transformers indicated that the licensee performed transformer gas-in oil analysis every month and electrical and chemical analysis twice a year. The inspector reviewed a summary of the oil analysis for the No. 1 auto transformer for the period of December 1988 to May 1992 which showed evidence of possible thermo-decomposition of cellulose due to overheating of transformer insulation. The licensee did not consider the issue an immediate concern but did increase monitoring of the oil from quarterly to monthly. The licensee stated that they performed transformer tests such as Doble, power factor, turns/turns, absorption and resistance checks on 10 year frequency. The last test was performed after the previous transformer failure in 1986. Depending upon the results of the root cause analysis of the disconnect switch and transformer failure, the inspection and maintenance program for these devices may need to be strengthened.

During the review of this event, the inspector asked the licensee whether they had reviewed the system stability considering operation of the plant without the No. 1 auto transformer. The licensee stated that stability studies without the No. 1 auto transformer in the system were performed following the previous transformer failure. Discussions with the licensee revealed that up to six Muddy Run pumps or up to eight Muddy Run generators (out of a total of 10 units) could be run to maintain reliable off-site power assuming a three phase fault on the Newlinville line, or a single phase fault on the Bradford line (at Muddy Run) with a stuck breaker. Licensee management stated that the load dispatcher had implemented administrative controls to restrict the Muddy Run plant operation following the failure of the No. 1 auto transformer on July 4.

At the end of this inspection, the licensee was replacing the failed transformer and disconnect switch. The exact cause of the transformer and disconnect switch failures had not been determined. The licensee stated that a thorough root cause analysis would be performed in order to determine the cause of the failures prior to re-energizing the No. 1 auto transformer. In addition, the breakers and associated relays would be calibrated and trip tested. The licensee committed to complete the root cause analysis on all equipment in the substation with the exception of the auto transformer by August 21, 1992. The licensee stated that the root cause analysis for the transformer would be completed as soon as possible.

Based on the licensee's administrative controls to restrict operation of Muddy Run and blocking of the reclosure feature on breakers 675 and 345, the inspector concluded that the licensee had taken appropriate short-term corrective actions to assure the reliability of the off-site power source until completion of the root cause analysis of the failures. To ensure long-term reliability of this offsite power source, it is important that the licensee continue with their efforts to identify the root causes of the failure. Licensee completion of the root cause analysis and inspector follow-up of the results is considered an unresolved item (50-278/92-14-01) and will be evaluated in a future NRC inspection.

3.2 E13 Bus Failure to Auto-Transfer

On July 4, shortly after the CRO manually transferred the E13 bus to the second source of offsite power, licensee technical personnel were at the TSC and on-site evaluating the failure. The inspectors observed licensee analysis activities in the TSC and observed troubleshooting and testing in the control room. These activities were well directed and controlled. Their initial determination was that the contacts on the control switch for breaker 152-1501, the feed breaker from the No. 3 startup regulating transformer switchgear, was not aligned properly. At about 7:00 a.m. on July 4, licensee technical personnel, through troubleshooting, successfully demonstrated that the control switch did not operate properly.

During this inspection, the inspector reviewed the control schematics for breaker 152-1501 operation and automatic transfer, performed a walkdown in the control room and interviewed several licensee personnel. The review determined that contacts 3 and 3C, and 4 and 4C on breaker control switch 152-1501/CS had not closed when the switch was last operated in February 1992. Failure of these contacts to close the feed breaker from the No. 3 startup regulating transformer switchgear resulted in the loss of the 125 Vdc power source to two agastat relay timers that are connected through a dead bus monitoring relay. A 0.25 second timer initiates the logic for auto-transfer of power for the bus to the second offsite source. A 0.50 second timer initiates logic for starting of the EDG, if the second off-site power source is not available. In this case, because of the loss of power to the agastat relay timers, neither the logic for the auto-transfer or starting of the EDG were initiated.

During the walkdown, the inspector noted that the handle position on the faulty switch was not exactly at the 12 o'clock position. It was found between 12 and 1 o'clock. The control switch was a General Electric (GE) type SBM with 3 stacks and had a date code of 10AY764. The licensee removed the faulty switch on July 7. An inspection of the switch revealed that the contacts failed to properly align after the switch sprang back to its normal return position after close. During the inspection, the licensee sent the switch to their Valley Forge Test Laboratory on July 8 for evaluation of the failure. The licensee stated that additional evaluation of the root cause of the switch failure would be completed by July 25, 1992. In the interim, the licensee provided information regarding the control switch failure to operations personnel to assure they were aware of the failure and the potential for failure of other control switches of this type. In addition, the licensee initiated a Training Request Form to ensure that the issue would be furthered discussed in requalification training until the root cause of the failure was identified and adequate corrective action could be taken. The inspector found the licensee's interim actions to be acceptable.

The licensee evaluated site specific and industry information for GE type SBM switches, and did not identify any indication of other similar problems. The inspector reviewed the vendor manual, maintenance history, surveillance tests, and applicable industry correspondence related to the GE type SBM switch in general and specifically to the control switch for breaker 152-1501. The objective of this inspection was to determine if this individual component failure could be representative of a more serious common cause failure. The inspector noted that the licensee had not established a preventive maintenance program for this type of SBM switch nor was one recommended by the vendor. The inspector's search of maintenance history did not identify any switch failures of this type in the past at Peach Bottom. The inspector noted that previous failures of General Electric SBM control switches had been reported in GE Service Information Letter (SIL) No. 155. The reported failures had been diagnosed as fracture of the Lexan cam followers. The SIL recommended that the licensees take actions if the SBM switches manufactured had certain date codes as shown in the SIL. The inspector noted that the subject switch did not fall under the date codes referenced in the SIL, and that the licensee's inspection of the failed switch did not identify evidence of this type of failure. In addition, the inspector performed a search of industry failure data for this type of switch. No other relevant failures were identified. The inspector also reviewed surveillance test ST-O-054-751-3, "E-13 4kV Bus Undervoltage Relays Functional Test," and ST-O-052-110-3, "D/G Simulated Auto Actuation and Load Acceptance" and found that the testing of the control switch for breaker 152-2501 was technically adequate.

The inspector observed removal of the faulty control switch on July 7, and replacement and testing of the new switch, on July 8 and 9. The inspector noted that all activities were performed using appropriate procedural controls and safety practices. The replacement switch, GE SBM control switch model 10AA108, was not identical to the original switch. The contact configuration differed slightly, therefore, the external wiring connections were changed. The licensee completed and approved Engineering Change Request (ECR) 92-184 prior to the installation of the new switch. The inspector reviewed the ECR and noted that it included evaluation of the acceptability of the replacement switch, detailed wiring instructions, and applicable drawing changes. The licensee performed a partial undervoltage functional test on the E13 bus per surveillance test procedure ST-O-054-751-3. The inspector observed the test from the control room. The control room operators directed the test in a controlled and coordinated fashion using proper communications and repeat backs. All aspects of the switch operation were tested and were satisfactory. Overall, the inspector found the activities associated with the removal of the faulty switch, and replacement and testing of the new switch to be acceptable.

In summary, the inspector concluded that the failure of the E13 bus auto-transfer to the alternate off-site power source or to the EDG was due to the faulty control switch for breaker 152-1501. The other Unit 2 and 3 emergency buses auto-transferred to the alternate power source as designed. In addition, all EDGs were available in case of a loss of all off-site power. The licensee's immediate actions to restore power to the bus and their interim corrective actions regarding operation's personnel awareness of the switch failure were found to be appropriate. In addition, the inspector found the licensee's past activities regarding maintenance, testing and evaluation of industry information for the switch to be acceptable. Completion of a detailed root cause analysis of the switch failure, and implementation of corrective actions in the long-term is needed to ensure the reliability of the large number of similar switches. Licensee completion of the root cause analysis and any additional corrective action regarding the failure of the control switch is considered an unresolved item (50-278/92-14-02) which will be reviewed during a future NRC inspection.

3.3 Unit 3 Reactor Scram

As previously discussed, Unit 3 experienced an automatic reactor scram on low condenser vacuum from about 95% power. Prior to the scram, as a result of the loss of the No. 343 start-up transformer and the E13 emergency bus, the RPS 'A' Motor-Generator (MG) set tripped causing a half scram and the 'B' Control Rod Drive (CRD) pump tripped. After the RO started the 'A' CRD pump, he experienced difficulty inserting control rods when attempting to reduce reactor power to mitigate the decreasing vacuum. The low vacuum scram setpoint of 23 inches Hg was reached, which initiated the automatic scram. Both recirculation pumps tripped as expected during their associated electrical bus auto-transfers. The ROs controlled and maintained reactor water level with the Reactor Core Isolation Cooling (RCIC) system.

During the event, the inspector observed the control room staff's scram recovery actions, and their restoration of the second offsite power source. During this inspection, the inspector reviewed alarm type and process computer data, critical recorder traces and control room logs to determine the sequence of events. The inspector also discussed the event with the appropriate operations personnel, and attended the Plant Operations Review Committee (PORC) meeting on July 8 during which GP-18, "Scram Review Procedure," was reviewed. In addition, the inspector attended the licensee's post-scram critique of the event at about 12:30 p.m. on July 4. The inspector determined that the appropriate procedures were utilized throughout the event. Off-Normal (ON), OT, and Transient Response Implementation Plan (TRIP) procedures were entered in a timely manner and rigorously executed. The inspector noted that the reactor was automatically shutdown, instead of the operators manually scramming the reactor due to the decreasing vacuum. This was due to the operators efforts in trying to recover condenser vacuum. Communications during the event appeared to be clear and concise. However, the radio communications between the OC at the North Substation and the control room were poor. The OC was forced to use the phone inside the relay blockhouse located in the substation a number of times, rather than his portable radio. This delayed vital communications to the control room and took the CO away from the scene. The OC was not able to use his radio because there are no repeaters installed at the substation. The inspector found that the licensee had previously approved modification 2523 to install a transmitter receiver in the north switchyard. This modification is scheduled for implementation during the next Unit 2 refueling outage in September.

After the event, Operations Management identified 13 open items which required resolution and presentation to PORC prior to restart of the unit. The inspector specifically followed the resolution of five of these items, considered to be the most significant, as discussed below.

- The loss of vacuum was caused by the loss of Panel 30Y33. Panel 30Y33 is powered from the E13 bus and supplies instrument power to the solenoids for the air-operated valves (AOVs) associated with the 'A' Steam Jet Air Ejector (SJAE). At the time of the event, the 'B' SJAE was in service and was not effected by the loss of power. The inlet AOVs to the first and second stages of the 'A' SJAE failed opened when the loss of power occurred. These AOVs are designed to fail "as-is" in the event of a loss of instrument air. However, with a loss of instrument power and instrument air available, the valves unexpectedly opened. This aligned the 'A' SJAE and the after-condenser to the 'B' SJAE suction. Water sealing a 12 foot loop seal on the 'A' SJAE after-condenser was sucked into the condenser resulting in a flowpath from atmosphere to the main condenser. The 'B' SJAE continued to operate normally, but was unable to maintain condenser vacuum and the off-gas system isolated on high after-condenser pressure. The licensee does not intend to change or modify the system at this time. However, the Training Department will review the failure mode of these valves with the operators, emphasizing loss of instrument power with instrument air available.

- The CRD system malfunctioned when Panel 10Y33 de-energized. Panel 10Y33 supplies instrument power to the Reactor Manual Control System (RMCS) Control Rod Drive Select Relay. This relay enables the RO to select and drive-in individual control rods. With this relay de-energized, the CRD system was disabled. The function of the control rods was unaffected. There was no licensee action required for this item.

- The trip of the 'A' RPS MG set was caused by exceeding the time delay relay settings of its control logic during the loss of power. A post-scram calibration check of this relay revealed that it was within its calibration and set for 5.6 seconds. The MG supply voltage was de-energized for 5.75 seconds. The licensee is investigating the feasibility of changing the timer to 8 seconds to provide an additional margin to prevent further spurious trips. The results of the investigation will be reviewed by PORC in August.

- During the event the narrow range reactor level indication failed downscale after level was raised above 60 inches. The narrow range reactor level indication is fed from the digital feedwater system. By design, the feedwater computer fails the narrow range level input signal to zero when reactor level is greater than 60 inches. Since there was no input to the control room indicators, they failed downscale. The level input signal is designed to fail downscale in order to allow the system to transfer to the wide range transmitters. As soon as level goes back below 60 inches, the computer switches back to the narrow range and the indicators function normally. The trip functioning provided by the transmitters, such as the low level scram, are unaffected. The licensee is initiating a design change to the digital feedwater level indication to prevent the level indication in the control room from failing downscale. In the interim, the licensee has informed all operations personnel through required reading, additional system review during training cycles, and establishment of an operator aid in the control room.

- Following the scram, the operators restarted the 'A' recirculation pump at 1:51 a.m. At 5:17 a.m., the 'A' pump was removed from service to allow transferring of the power source from the No. 2 startup transformer switchgear back to the No. 3 startup regulating transformer switchgear. At 5:21 a.m., the operators attempted to restart the 'A' pump, but the MG set tripped on overcurrent due to the field breaker closing at the same time as the drive motor breaker. Upon troubleshooting, licensee personnel found a bolt in the pump start timer which had caused the MG set to trip. The start timer assures that the MG set reaches the proper speed prior to the pump motor starting. The licensee determined that the bolt had fallen from the overhead lighting raceway in the cabinet. The bolt was replaced and the licensee verified that the other bolts in this cabinet as well as the Unit 2 cabinet were secure. At 3:09 a.m. on July 5, the operators successfully restarted the 'A' recirculation pump.

  The operators attempted to restart the 'B' recirculation pump at 1:58 a.m. on July 4, but the MG set drive motor breaker opened after 62 seconds. The licensee initially believed that the 'B' pump had failed to start, due to the improper setting of the interlocks that trip the drive motor breaker three minutes after generator field breaker closure if the pump discharge valve is not full open. The 'B' pump was successfully restarted on July 6 at 2:21 p.m. The licensee tested the interlocks on July 7 and found that the interlocks were properly set. At the end of the inspection, the licensee had not determined the reason the 'B' pump could not be started. The inspector concluded that the licensee's actions regarding evaluation of the difficulties in starting the recirculation pumps were appropriate.

The operator's actions during the event were appropriate and within the guidance of their procedures. Although they did not know the causes of the malfunctions they experienced at the time of the event, the operators followed their response procedures and maintained the reactor in a safe condition. Face-to-face communications in the control room were adequate. However, time was lost and some communications delayed due to the OC's need to use the telephone rather than communicate directly with his radio. Licensee management took an active role and demonstrated a strong safety focus in the review of open issues that required resolution prior to the restart of the unit.

3.4 Emergency Preparedness

The licensee notified the NRC of the Alert declaration and enabled the Emergency Response Data System at 2:41 a.m. on July 4. The NRC entered the monitoring mode and staffed the Region I Incident Response Center (IRC) in King of Prussia, Pennsylvania, at about 3:10 a.m. The communications counterpart link between the IRC and the Peach Bottom control room was established. Licensee briefings to the IRC were clear and informative. In addition, two NRC

Resident Inspectors for Peach Bottom arrived at the site at about 4:00 a.m. The inspectors monitored licensee recovery activities in the control room and the TSC. Licensee technical personnel in the TSC were focused on relevant technical issues involving the loss of off-site power and the emergency bus failure to auto-transfer. Shortly following the event on July 4, the inspector attended a licensee event critique performed by operations, technical and maintenance personnel involved in the event. The inspector found the critique to be very useful in identifying the appropriate issues on which to focus prior to restart of Unit 3. The technical personnel who had manned the TSC during the event held a critique on July 8 and identified various strengths and weaknesses associated with the activation and manning of the TSC. The inspector found the critique to be very useful in identifying ways to improve the licensee's emergency response effort.

During this inspection, the inspectors reviewed event logs, use of Emergency Response Procedures (ERPs) during the event, training records, news releases, and other records associated with response actions, and interviewed licensee personnel. As documented in the following, the emergency plan actions taken by the licensee's ERO were timely and in accordance with established ERPs. Emergency classification, communications with off-site authorities, decision-making by shift staff, and overall coordination of the response were found effective.

The inspectors primarily focused on the following: timeliness of classification, timeliness of notifications, activation of Emergency Response Facilities (ERFs) once the event was classified, and accuracy of records maintained in each ERF.

The following are from the chronology of events reconstructed through review of the July 4, 1992 event logs and interviews with on-shift personnel as presented in Section 2.0 of this report.

- At 1:10 a.m., an OC reports to the control room that there was arcing and light at the North Substation. OC dispatched to investigate.
- At 1:18 a.m., OC reports a fire in the North Substation.
- At 1:19 a.m., Unit 3 receives a half scram and several electrical alarms. Condenser vacuum begins decreasing.
- At 1:27 a.m., Unit 3 scram occurs as a result of low condenser vacuum.
- About 1:40 a.m., the OC reports an explosion at the North Substation.
- At 1:50 a.m., the SM declares an Alert due to "significant explosion affecting plant operation," (ERP-101 Table 12).

Because the fire at the North Substation was reported at 1:18 a.m. and the Alert was declared at 1:50 a.m., event classification timeliness was evaluated. Discussion with the SM indicated that, although a fire was confirmed in the North Substation at 1:18, the report was received at the same time the fire was extinguished. The inspectors reviewed ERP-101 and noted that, consistent with NRC requirements, an off-site fire was not an initiating condition for an emergency classification. The SM continued to follow the events and considered the electrical problems and the explosion at the North Substation at 1:40 a.m. to be related. At this time, he entered the ERPs to review the emergency action level scheme and declared an Alert at 1:50 a.m., 10 minutes after conditions meeting an Alert classification criterion (an explosion affecting plant operation) became evident. The inspectors noted the 1:40 a.m. entry in the SSV log reporting the explosion at the North Substation, and concluded that the Alert classification was appropriate and timely.

Timeliness of notifications and activation of the ERFs were also evaluated. Upon declaration of the Alert, the Shift Clerk began notification of off-site authorities in accordance with ERP-110, Appendix 1. The Commonwealth of Pennsylvania, the State of Maryland, and the five affected counties were notified by 2:02 a.m. The NRC was notified at 2:41 a.m. These notifications met NRC timeliness requirements.

The OSC was activated at 2:20 a.m., which was very timely. However, the TSC was not activated until 3:45 a.m., one hour and fifty-five minutes after declaration of the Alert. The inspectors identified the following reasons for the delay in for TSC activation:

- The ERP-110 notification required the ED's Communicator to complete the 15-minute notifications and then call out the ERO per ERP-140. This cumbersome procedure necessitates preparation of answering machines and the voice mail system before pagers can be activated. As a result, pagers were not activated until 2:25 a.m., 35 minutes after declaration.

- The weather at the time was rainy and foggy, limiting the response speed of responders.

- The SM was tied up on the telephone with senior management and public information personnel. That delayed his turnover to the ED in the TSC from about 3:15 a.m. until 3:45 a.m.

The inspector noted that the licensee identified TSC activation timeliness as a weakness. Their immediate corrective action was a memo from the Station Vice President to SMs and EDs, instructing them that TSC activation takes precedence over any other phone communications. The licensee committed to revise the procedures for notifications and ERO callout to reduce the time between event declaration and activation of the ERO, by August 20, 1992. The licensee may task security with ERO callout. In the long-term, the licensee has plans in place to install an automated callout system. Inspector review concluded that acceptable corrective action had been implemented on this matter.

Logkeeping in the control room and TSC was reviewed. The control room logs were generally good, but were sketchy about communications from the OC on what was happening in the North Substation (e.g., whether there was a fire and/or explosion). It was stated by the control room staff during the interviews that logs were not maintained during the incident, but were reconstructed after the plant was stabilized. Plant events were obtained from the plant computer printout, but communications between plant personnel are not automatically logged and were left to memory. The Emergency Director's log was also very sketchy. His log for a three-hour period was about one-third of a page long, and there were several entries of "Conf. call initiated" with no details of the calls or participants.

Overall, the licensee appropriately implemented the Emergency Plan and Emergency Plan Implementing Procedures. The activities observed in the TSC were well directed and briefings provided by the licensee to the NRC were good. The licensee is taking action to correct the weaknesses observed in TSC activation timeliness and logkeeping.

4.0 CONCLUSIONS

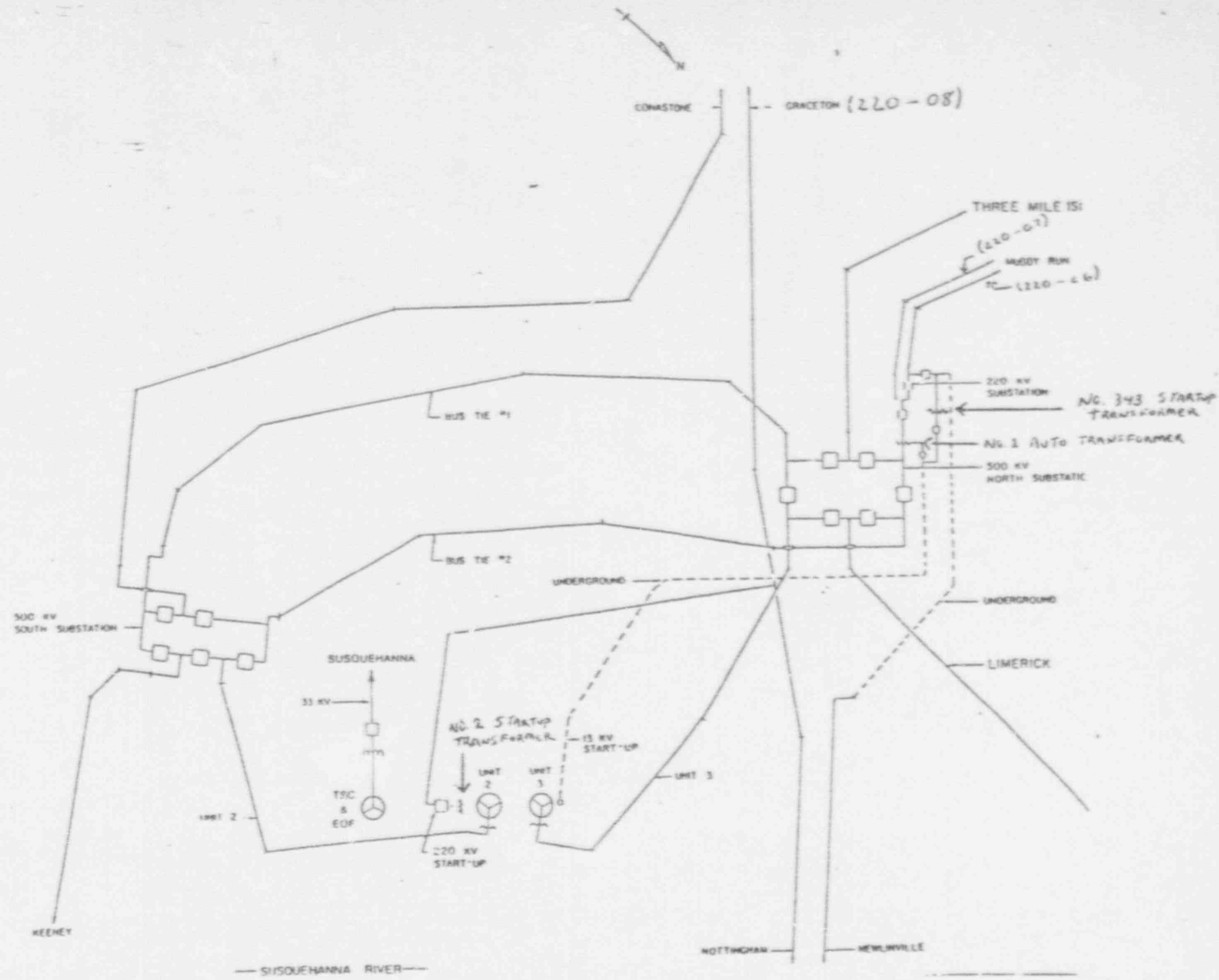
During this event, one of two off-site power sources was lost due to the failure of the No. 1 auto transformer, the failure of the No. 173 disconnect switch and the opening of the 3435 breaker. In addition, power was lost to one 4 kV emergency bus for Unit 3 for a period of about six minutes due to the failure of control switch for breaker 152-1501. This loss of power resulted in a Unit 3 reactor scram on low condenser vacuum. The SM declared an Alert due to an explosion in the North Substation and the licensee's ERO was activated. The actual safety significance of the event was low. However, the coincident failures resulting in the loss of one offsite power source and failure to energize one safety-related 4 kV bus should be viewed as an event precursor and evaluated accordingly.

Overall, the inspectors concluded that the licensee had appropriately evaluated all issues, specifically those related to the availability of the off-site power source and the loss of power to the emergency bus. The inspectors determined that the licensee's operational and emergency planning response to the event were appropriate. The inspectors found the licensee's immediate and interim corrective actions related to the failures of the transformer, the disconnect switch, and the breaker control switch to be acceptable. In addition, the licensee has committed to complete the root cause analyses of the failures in the substation and of the control switch in a timely manner.

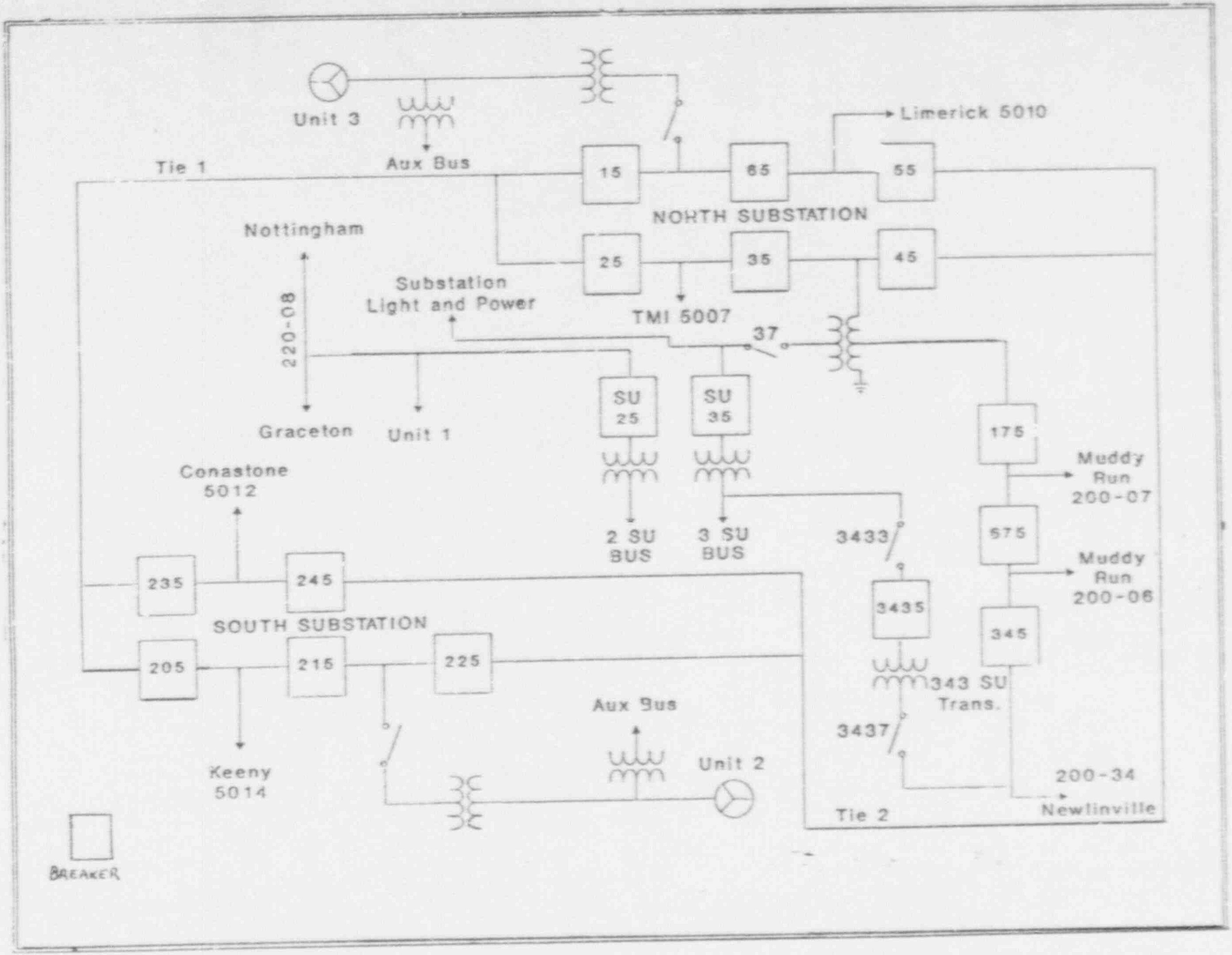
Station management took an active role in the review and closure of all issues. The engineering staff was knowledgeable and provided good support for analysis and resolution of the issues. Good communication existed between the Transmission and Distribution Department and the plant to address the substation issues.

ATTACHMENT A

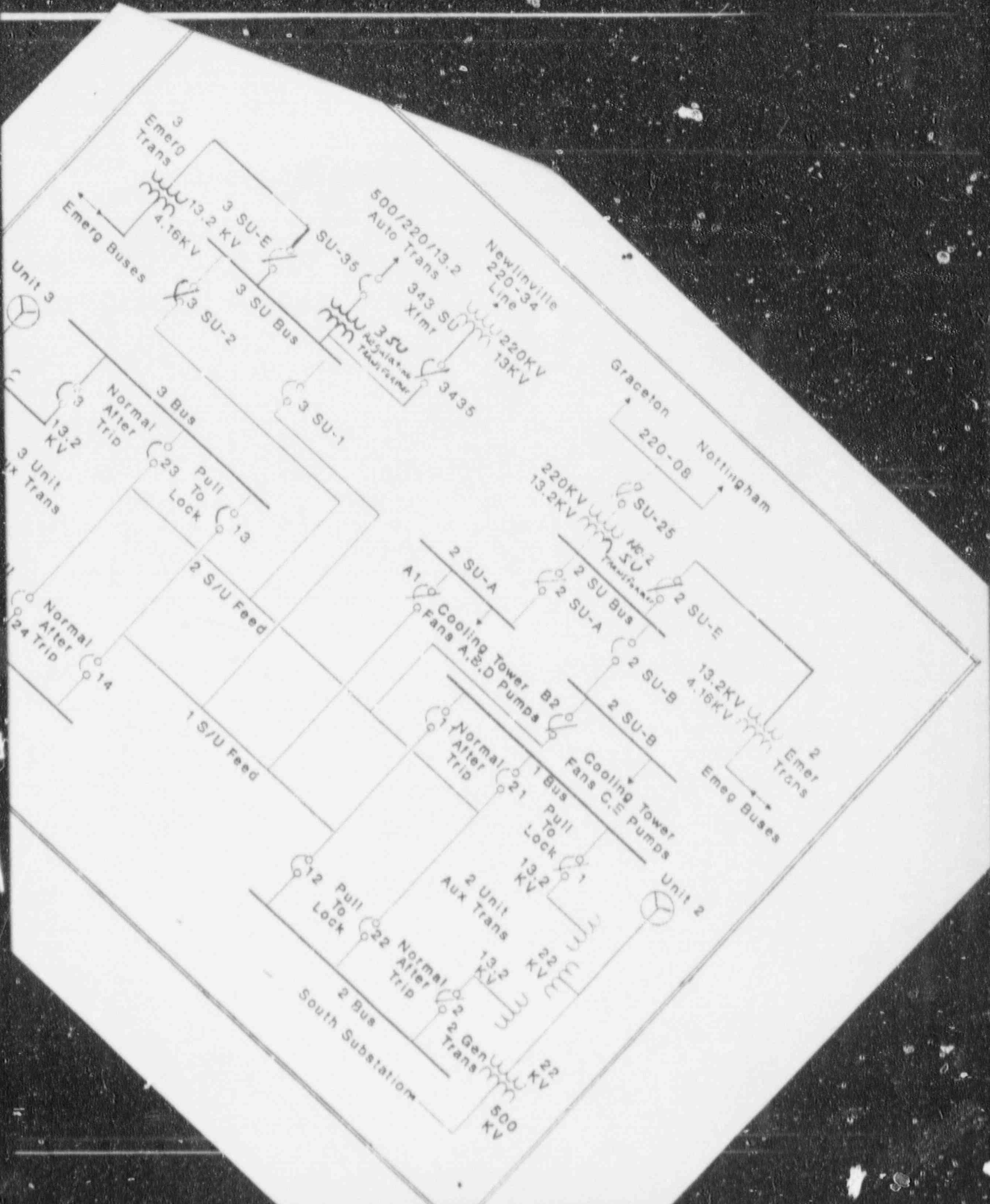
PEACH BOTTOM ATOMIC POWER STATION
SIMPLIFIED ELECTRICAL DISTRIBUTION DRAWINGS



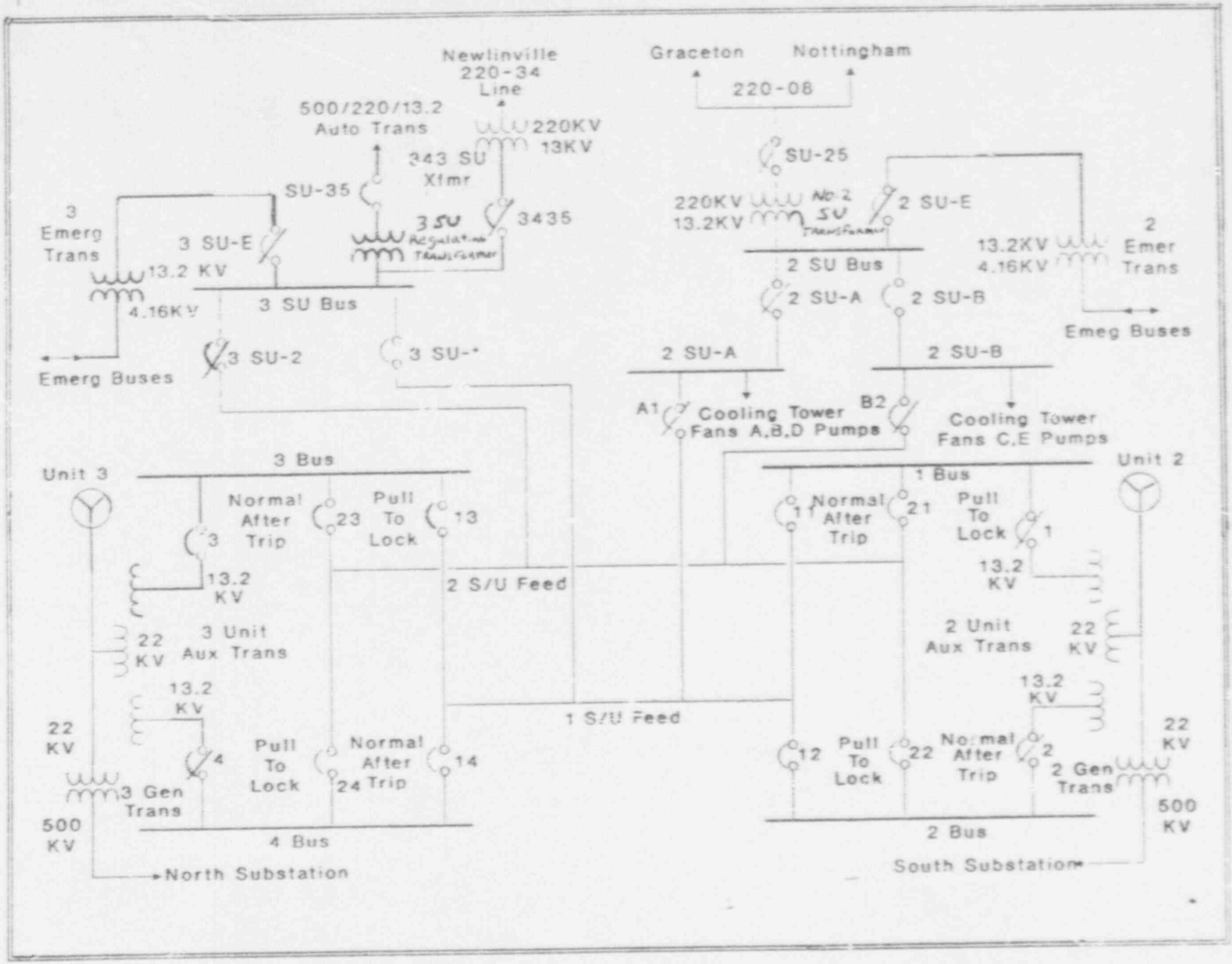
N
CONASTONE
GRACETON (220-08)
THREE MILE IS:
(220-07)
MUDDY RUN
TC (220-26)
220 KV
SUBSTATION
NO. 343 STARTUP
TRANSFORMER
NO. 1 AUTO TRANSFORMER
500 KV
NORTH SUBSTATIC
BUS TIE #1
BUS TIE #2
UNDERGROUND
UNDERGROUND
LIMERICK
500 KV
SOUTH SUBSTATION
SUSQUEHANNA
33 KV
NO. 2 STARTUP
TRANSFORMER
13 KV
START-UP
UNIT 2
UNIT 3
UNIT 3
TSC
&
EOF
UNIT 2
220 KV
START-UP
KEENEY
NOTTINGHAM
NEWLINVILLE
SUSQUEHANNA RIVER



Unit 3
Aux Bus
Limerick 5010
Tie 1
15
65
55
NORTH SUBSTATION
Nottingham
25
35
45
Substation
Light and Power
TMI 5007
37
220-08
SU 25
SU 35
Graceton
Unit 1
175
Muddy Run 200-07
Conastone 5012
2 SU BUS
3 SU BUS
3433
575
Muddy Run 200-06
235
245
3435
SOUTH SUBSTATION
345
205
215
225
343 SU Trans.
Aux Bus
3437
Keeny 5014
Unit 2
200-34
Tie 2
Newlinville
BREAKER



3 Emerg Trans
13.2 KV
4.16KV
3 SU-E
Emerg Buses
SU-35
500/220/13.2 Auto Trans
343 SU Xfmr
Newlinville 220-34 Line
220KV
13KV
3 SU Regulating Transformer
3435
3 SU Bus
3 SU-2
3 SU-1
Unit 3
3 Bus
Normal After Trip
3
13.2 KV
3 Unit Aux Trans
23
Pull To Lock
13
Graceton
220-08
Nottingham
SU-25
220KV
13.2KV
No. 2 SU Transformer
2 SU-A
2 SU Bus
2 SU-E
2 SU-A
A1
Cooling Tower B2 Fans A,B,D Pumps
2 S/U Feed
Normal After Trip
24 Trip
14
2 SU-B
2 SU-B
13.2KV
4.16KV
2 Emer Trans
Emeg Buses
1 S/U Feed
11 Normal After Trip
1 Bus
Cooling Tower Fans C,E Pumps
21
Pull To Lock
1
13.2 KV
Unit 2
12
Pull To Lock
2 Unit Aux Trans
22
22 Normal After Trip
13.2 KV
22 KV
2
2 Gen Trans
2 Bus
South Substation
22 KV
500 KV



Newlinville
220-34
Line
Graceton
Nottingham
220-08
500/220/13.2
Auto Trans
220KV
13KV
343 SU
Xfmr
SU-35
3435
3 SU
Regulating
Transformer
SU-25
220KV
13.2KV
No. 2
SU
Transformer
2 SU-E
3
Emerg
Trans
3 SU-E
13.2 KV
4.16KV
3 SU Bus
2 SU Bus
2 SU-A
2 SU-B
13.2KV
4.16KV
2
Emer
Trans
Emeg Buses
Emerg Buses
3 SU-2
3 SU-1
2 SU-A
2 SU-B
A1
Cooling Tower
Fans A,B,D Pumps
B2
Cooling Tower
Fans C,E Pumps
Unit 3
3 Bus
Normal
After
Trip
23
Pull
To
Lock
13
3
13.2
KV
2 S/U Feed
22
KV
3 Unit
Aux Trans
13.2
KV
4
Pull
To
Lock
24
Normal
After
Trip
14
22
KV
3 Gen
Trans
500
KV
4 Bus
North Substation
1 S/U Feed
Unit 2
1 Bus
11
Normal
After
Trip
21
Pull
To
Lock
1
13.2
KV
2 Unit
Aux Trans
22
KV
13.2
KV
12
Pull
To
Lock
22
Normal
After
Trip
2
2 Gen
Trans
22
KV
500
KV
2 Bus
South Substation