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Office of Nuclear Reactor Regulation, Director

SUBJECT: Forwards responses to 830831 & 15 confirmatory action ltrs re actuation of degraded voltage protection logic on 830801. No technical reason for not transferring station auxiliary loads to reserve station auxiliary transformer 1.

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Northern States Power Company

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September 9, 1983

Director
Office of Nuclear Reactor Regulation
U S Nuclear Regulatory Commission
Washington, DC 20555

MONTICELLO NUCLEAR GENERATING PLANT
Docket No. 50-263 License No. DPR-22

Information Related to Actuation of
Degraded Voltage Protection Logic on August 1, 1983
at the Monticello Nuclear Generating Plant

The purpose of this letter is to respond to a Confirmatory Action Letter dated August 31, 1983 from Mr J G Keppler, Regional Administrator, Region III, US Nuclear Regulatory Commission. This letter requested that we address seven additional items related to the August 1, 1983 event in which automatic degraded voltage protection logic for bus 16 was actuated. In addition, we were requested to provide further clarifying information related to item (3) of the August 15, 1983 Confirmatory Action Letter related to the same event.

Our responses to these items are provided as attachments to this letter. We will be prepared to discuss this information in detail at a meeting we have scheduled with our Project Manager in the Division of Licensing for September 13, 1983 at the NRR Offices in Bethesda, Maryland.

As noted in our response to item (5), we have found no technical reason for not transferring station auxiliary loads to the No. 1 Reserve Station Auxiliary Transformer and have done so. Except for the purpose of performing corrective maintenance on No. 1 Reserve Station Auxiliary Transformer, we will not return the station auxiliary loads to the No. 11 Auxiliary Transformer without NRC concurrence. We believe, however, that the information provided for NRC Staff review in our August 24, 1983 letter and in this letter provides a basis for returning the station auxiliary loads to the No. 11 Auxiliary Transformer in accordance with the original plant design. We would ask that NRC concurrence with this action be discussed at our September 13, 1983 meeting.

Please contact us if you have any questions related to the actions we have taken to resolve the Commissions concerns related to this matter.

David Musolf

David Musolf
Manager - Nuclear Support Services

A001
1/1

DMM/bd

cc: J G Keppler
NRR Project Manager, NRC
Resident Inspector, NRC
G Charnoff

Attachments

3. Provide for NRR review by September 12, 1983, an analysis of all available methods of maintaining the proper minimum operating voltages on your 4160 volt ac essential buses. The results of your analysis will assure that you are using the best method to reliably maintain the voltages."

RESPONSE

Administrative controls have been issued to ensure proper actions are performed by operations personnel in maintaining essential bus voltages above the established minimum operating levels.

These minimum operating voltage levels were determined as described in item 1 of Northern States Power Co. transmittal August 24, 1983 from Mr. D. Musolf, Manager-Nuclear Support Services to the Director, Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission.

Hourly logging of the station auxiliary voltages coupled with the action alarm points ensure that these minimum operating voltages are not exceeded. Procedures are in place for operator action once the action points have been alarmed.

It was demonstrated with testing and monitoring at 100% power that these procedures are adequate for reliably maintaining essential 4160 volt bus voltages. During the past light load weekend (Sept. 3-5, 1983) where system grid voltage is high and system demand low, operator action ensured proper essential bus voltages were maintained as generator terminal voltage was adjusted for system grid conditions. In addition, testing showed that the essential bus voltages could be maintained between the minimum and maximum levels as the load tap changer (LTC) on No. 10 transformer lowered and raised the 115Kv grid between 118.8 Kv and 125Kv. Further testing proved the same was true on the essential buses as the generator terminal voltage was adjusted between 21.53 Kv and 23.01Kv.

The measures described have been deemed by Northern States Power Company to reliably maintain the voltages on the 4160 volt ac essential buses.

5. Evaluate the feasibility of operating the 4160 buses from an offsite source of power during normal plant operations and transfer to that source of power unless your evaluation reveals a technical basis for not doing so, and submit the results of your evaluation to NRR by September 12, 1983. Should you transfer to offsite power, we understand that you would revert back, on a short-term basis and to the minimum extent possible, to No. 11 Auxiliary Transformer as a source of power to the 4160 ac essential buses only if corrective maintenance on the offsite power sources necessitated such action.

RESPONSE

I. OPERATION WITH STATION AUXILIARY LOADS SUPPLIED FROM NO. 11 STATION AUXILIARY TRANSFORMER

A.) No. 11 STATION AUXILIARY TRANSFORMER

The No. 11 Station Auxiliary Transformer is a 21.7 Kv - 4.16Kv-4.16Kv, 38,000 Kva transformer with dual low voltage windings. The transformer high voltage winding is connected to the generator terminals through iso phase bus duct and the low voltage windings are connected to the 4.16Kv station auxiliary switchgear through non-segregated phase bus duct. See Attachment 1, Diagram GF-1660.

The low voltage winding designated "X" supplies power to the large motor buses No. 11 and No. 12 while the low voltage winding designated "Y" supplies power to No. 13 and No. 14 buses which in turn supply power to the ECCS buses No. 15 and No. 16 respectively.

The No. 11 Station Auxiliary Transformer is connected delta-wye with high resistance grounded wye neutrals to limit available ground fault current to the 4.16Kv switchgear.

The exclusive purpose of No. 11 Station Auxiliary Transformer is to supply the unit station auxiliary loads during unit operation. Transfer of the station auxiliary loads from the No. 1 Reserve Station Auxiliary Transformer to No. 11 Station Auxiliary Transformer is a "manual, make before break" operation performed by the operator, after the generator has been synchronized and connected to the 345Kv system.

The transfer is supervised by synchrocheck relays to prevent paralleling of the two station auxiliary transformers in the event an excessive phase angle between the two exists.

Protective relaying for No. 11 Station Auxiliary Transformer consists of transformer differential, sudden pressure, and ground overcurrent relaying. Operation of any one of the protective relays will trip the auxiliary transformer lockout relay which in turn trips No. 1 Generator lockout relay. Operation of the No. 1 Generator lockout relay will simultaneously trip the generator gas circuit breakers, turbine master trip solenoids, generator field breaker and initiate an automatic fast (break before make) transfer of the station auxiliary loads to No. 1 Reserve Station Auxiliary Transformer.

In addition to the aforementioned protective relaying, transformer winding temperature, transformer oil temperature, and transformer oil level indicators with alarm contacts are provided.

B.) NORMAL OPERATION

During normal operation, with the generator on line, and the station auxiliary loads supplied from No. 11 Station Auxiliary Transformer, No. 1 Generator serves as the source of station auxiliary power. This mode of operation offers three distinct advantages over other, off-site, sources of station auxiliary power:

1) The generator excitation system is equipped with a generator voltage regulator which provides the operator the option of either "Manual" control or continuously acting "Automatic" control of the generator terminal voltage, and therefore station auxiliary bus voltage.

2) Any desired generator voltage, within established operating limits, can be selected by the operator either in "Manual" mode or by adjustment of the desired voltage setpoint of the "Automatic" voltage regulator.

3) Power transformer losses incurred as a result of supplying the station auxiliary loads are minimized by supplying this load directly from the generator terminals.

The first two are, of course, the most relevant and will be discussed further.

C.) VOLTAGE CONTROL

An important aspect, pertinent to supplying reliable station auxiliary power is the ability of the operator to adjust the voltage level on the station auxiliary buses and that the level selected by the operator is automatically and continuously regulated by the generator automatic voltage regulator.

The excitation system provided at Monticello is the General Electric "Alterrex" system which is equipped with both a "Manual" control system which requires the operator to adjust the generator terminal voltage and an "Automatic" voltage regulator which, when placed into service by the operator, automatically and continuously regulates the generator terminal voltage at a value preselected by the operator.

Characteristic features of the automatic voltage regulator and excitation system are as follows:

Performance

1) With the excitation system in "Manual" mode the generator terminal voltage is adjustable from 80% of rated voltage no load to 100% of rated voltage full load, at .90 power factor.

2) With the excitation system in "Automatic" mode the generator terminal voltage set point is adjustable between ± 7.5% of generator rated voltage.

3) The excitation system response is .5 seconds. This means the excitation will respond from rated voltage at full load to maximum ceiling voltage in approximately 1/2 second.

4) Typical terminal voltage response time, of units equipped with the "Alterrex" excitation system, is one percent/second.

5) Analysis indicate that the generator excitation system is capable of providing sufficient field current to allow the generator terminal voltage to be maintained within an acceptable range to provide the station auxiliary bus voltages necessary in spite of relatively wide fluctuations in 345Kv bus voltage. Results of the analysis are as follows:

	Minimum	Maximum
Generator Terminal Voltage	22.06Kv	23.0Kv
Generator Megawatt Load	560 Mw	560 Mw
Generator Reactive Load	+280 MVAR	-200 MVAR
Station Auxiliary Megawatt Load	27 Mw	27 Mw
Station Auxiliary Reactive Load	17 MVAR	17 MVAR
345Kv Bus Voltage	333 Kv	372 Kv

It should be noted that the generator voltage range of 22.06Kv to 23.0 Kv was previously determined to be acceptable with station auxiliary bus undervoltage relay settinas of 3885 volts, and existing relay reset dead band.

Protective Features

1) Maximum excitation relaying exists which will initiate an alarm and operate to limit the generator exciter field voltage and therefore generator field current if the generator field voltage exceeds 120% of rated voltage full load. This protection is provided to limit generator field heating during disturbances.

2) Volts/Hertz relaying exists which will initiate an alarm, operate to runback the manual control setting and transfer the excitation control to manual if the ratio of generator terminal volts to frequency reaches 2.2 for 10 seconds (110% rated terminal voltage at 60 Hertz). If the generator breakers are open the generator field breaker will be automatically tripped if excessive Volts/Hertz persists for 60 seconds.

3) Under excitated reactive limit circuitry exists which will automatically limit the amount of leading power factor reactive power carried by the generator. The limiter only functions when the generator voltage regulator is in the "Automatic" mode.

4) Loss of field relaying exists which will trip the generator lockout relay, resulting in an automatic transfer of the station auxiliaries if the generator reaches an operating point near the steady state stability limit.

In addition to the automatic voltage regulating features and protective features of the excitation system a number of meters and analog computer points exist to allow the operator to not only routinely monitor status of the unit but which will also alert the operator if certain critical operating limits are approached or exceeded:

1) Generator terminal voltage meters.
2) Computer alarms if generator terminal voltage limits are reached.
3) 4.16Kv Station Auxiliary bus voltmeters.
4) Computer alarms if 4.16Kv station auxiliary bus voltage limits are approached.
5) Generator Megawatt and Megavar meters
6) 4.16Kv Station Auxiliary bus ammeters for Buses 11,12,13,14
7) Generator ammeters
8) 345 Kv substation bus voltmeters.
9) Computer analog point for 115Kv bus voltage.
10) Computer alarms if 345Kv or 115Kv bus voltages approach unacceptable levels.

D.) TRANSFER OF STATION AUXILIARY LOADS BETWEEN No. 11 STATION AUXILIARY TRANSFORMER AND No. 1 RESERVE STATION AUXILIARY TRANSFORMER

As previously mentioned the transfer of the station auxiliary loads from the No. 1 Reserve Station Auxiliary Transformer to No. 11 Station Auxiliary Transformer is a "make before break" transfer performed by the operator after the generator is connected to the transmission system. The transfer is supervised by synchrocheck relays which will prevent the transfer if the phase angle between the two sources exceeds 20 degrees. Transfer of the station auxiliary loads from No. 11 Station Auxiliary Transformer to No. 1 Reserve Station Auxiliary Transformer is performed in a similar manner with the transfer also supervised by synchrocheck relays. This transfer is performed by the operator prior to opening the generator gas circuit breakers when removing the generator from service, although it may be performed at any time.

The station auxiliary loads are also automatically transferred from No. 11 Station Auxiliary Transformer to No. 1 Reserve Station Auxiliary Transformer on unit trips. Two methods of automatic transfer are employed and the occurrence of each depends upon the cause of the unit trip, although both are supervised by synchrocheck relays. A "make before break" or "closed" transfer is initiated for unit trips not involving the operation of electrical protective relays. A "break before make" or "open-fast" transfer is initiated for unit trips involving the operation of electrical protective relays. If either transfer should fail loss of voltage relays will drop out at 63% of nominal voltage on the 4.16Kv buses to allow dead bus pickup.

The initiating causes of unit trips and type of transfer are listed:

Initiating Cause of Trip	Type of Automatic Transfer
Generator Emergency Trip	Open
Generator Neutral Overvoltage	Open
Generator Transformer Sudden Pressure	Open
Generator Differential	Open
Main Transformer and Generator Differential	Open
345Kv Substation Relaying	Open
11 Station Aux Transformer Lockout	Open
Generator Overcurrent	Open
Turbine Lockout with Gen. Negative Sequence	Open
Turbine Emergency Trip	Closed
Moisture Separator High Level	Closed
Turbine Thrust Wear	Closed
Turbine Exhaust Hood Temperature	Closed
Turbine High Vibration	Closed
Condenser Vacuum Low	Closed
Generator Loss of Field	Closed
Loss of Generator Stator Cooling	Closed
Reactor High Water Level	Closed

In addition, all trips which result in automatic transfer of the station auxiliary loads also initiate a trip of the Reactor Recirculation Pumps to prevent excessive in rush currents from No. 1 Reserve Transformer in the event that the transfer did not occur properly.

II. OPERATION WITH STATION AUXILIARY LOADS SUPPLIED FROM No. 1 RESERVE STATION AUXILIARY TRANSFORMER

A.) No. 1 Reserve Station Auxiliary Transformer is a 115Kv - 4.16Kv - 4.16Kv, 33,333 Kva transformer with dual low voltage windings. The transformer high voltage winding is connected to the 115Kv substation bus through a 115Kv gang operated disconnect switch and overhead transmission line. The low voltage windings are connected to the 4.16Kv switchgear through non-segregated phase bus duct. The low voltage winding designated "X" supplies power to the large motor buses No. 11 and No. 12, while the "Y" winding supplies power to bus No. 13 and No. 14 which in turn supply power to the ECCS buses No. 15 and 16 respectively.

The No. 1 Reserve Station Auxuliary Transformer is connected wye-wye with high resistance grounded wye neutrals on the 4.16Kv windings to limit available ground fault current to the switchgear.

No. 1 Reserve Station Auxiliary Transformer is intended to supply the unit station auxiliary loads during unit startup, unit shutdown, or whenever otherwise required. Transfer of the station auxiliary loads between No. 1 Reserve Station Auxiliary Transformer and No. 11 Station Auxiliary Transformer is discussed in Section I of this response.

Protective relaying for No. 1 Reserve Station Auxiliary Transformer consists of transformer differential, sudden pressure, ground overcurrent, and backup overcurrent relays. Operation of any one of the protective relays will trip the transformer lockout relay which will trip the 115Kv substation source breakers to No. 1 Reserve Station Auxiliary Transformer as well as the 4.16Kv air circuit breakers connected to the low voltage windings, and also initiate a start of the emergency diesels. Station auxiliary loads being supplied by No. 1 Reserve Station Auxiliary Transformer will be de-energized. Only 4.16Kv buses No. 15 and No. 16 (ECCS) will be automatically reenergized by No. 1 AR Transformer. All other station auxiliary loads will be without a source of power.

In addition to the aforementioned protective relays, transformer winding temperature, transformer oil temperature, and transformer oil level indicators with alarm contacts are provided.

B.) NORMAL OPERATION

During operation with No. 1 Reserve Station Auxiliary Transformer supplying the unit auxiliary loads power is supplied from the 115Kv substation which consists of a breaker and a half scheme. The 115Kv substation is connected to the Company's transmission system through three 115Kv transmission lines and a 336 MVA auto transformer equipped with a Load Tap Changer (LTC). The LTC has ± 16 - 5/8% taps and is set to automatically regulate the 115Kv substation bus voltage at 120Kv ± 1 Kv.

C.) VOLTAGE CONTROL

Voltage control of the 115Kv substation bus, which supplies No. 1 Reserve Station Auxiliary Transformer is provided by automatic operation of the load tap changer on No. 10, 345-115Kv Transformer. The LTC operates through 32 discrete tap positions to regulate the 115Kv bus voltage at 120Kv ± 1 Kv. The LTC response is approximately 1.5 seconds per tap change and a ± 1 Kv dead band exists.

Monticello plant operators have the ability to manually operate the LTC to adjust the 115Kv substation voltage should it become necessary. The controls for operating the LTC are located in the 345Kv-115Kv substation control house. The operators as well as the System Operators have 115Kv bus voltage indicators and High/Low alarms exist to alert the plant operators and the System Operators if the 115Kv bus voltage approaches unacceptable limits.

D.) TRANSFER OF STATION AUXILIARY LOADS

1) Transfer of station auxiliary loads between No. 1 Reserve and No. 11 Station Auxiliary Transformer is discussed in Section I of this response.

2) Transfer of No. 15 and No. 16 4.16Kv buses to No. 1 AR Transformer will automatically occur when undervoltage relays, sensing voltage on the 4.16Kv windings of No. 1 Reserve Station Auxiliary Transformer drop out. Operation of these undervoltage relays will, after a 2 second time delay, trip No. 1 Reserve Station Auxiliary Transformer 4.16Kv air circuit breakers to buses 11,12,13, and 14. Tripping of the source breaker to buses No. 13 and No. 14 will in turn trip the source breakers to buses No. 15 and No. 16 after a 5 second time delay. Loss of voltage on buses 15 and 16 will in turn result in ECCS bus load shedding, closure of No. 1 AR Transformer to Bus 15 and Bus 16 air circuit breakers, and a start of the emergency diesel generators.

III. SUMMARY

A.) OPERATION WITH STATION AUXILIARY LOADS SUPPLIED FROM No. 11 STATION AUXILIARY TRANSFORMER

1) Station auxiliary loads are supplied from No. 1 Generator terminals.

2) No. 1 Generator terminal voltage can be manually adjusted to maintain desired voltage on the 4.16Kv buses.

The generator automatic voltage regulator set point can be adjusted by the operator and the voltage regulator will function to automatically and continuously regulate the generator terminal voltage.

The generator excitation system is designed with a response of .5, meaning the excitation level will respond to maximum ceiling voltage in approximately 1/2 second if required.

The generator terminal voltage response to an error signal step change is typically one percent/second with the automatic voltage regulator in service.

3) Analysis indicates that the generator terminal voltage range required to maintain acceptable 4.16Kv bus voltage can be achieved with 345Kv substation bus voltages varying between 333Kv and 372Kv.

Therefore, station auxiliary 4.16Kv bus voltages will not be affected by variations of the 345Kv substation bus voltages from 333Kv to 372Kv, and will not be affected by variations of the 115Kv bus voltage or disturbances in the 115Kv system.

4) A turbine/generator trip will result in an automatic transfer of all station auxiliary loads, except the Reactor Recirculation Pumps, to No. 1 Reserve Station Auxiliary Transformer, allowing an orderly shutdown.

In the event the No. 1 Reserve Station Auxiliary Transformer is not available, as sensed by undervoltage relays on the secondary of the transformer, ECCS buses No. 15 and No. 16 will be re-energized by No. 1 AR Transformer or the emergency diesel generators.

5) Meters and computer analog points exist to allow routine monitoring of the generator and 4.16Kv bus voltages as well as alarm to alert the operator if bus voltages approach unacceptable levels.

6) A computer load flow analysis, the results of which were submitted August 24, 1983, indicate that the normal and ECCS loads can be successfully supplied from No. 11 Station Auxiliary Transformer.

B.) OPERATION WITH STATION AUXILIARY LOADS SUPPLIED FROM No. 1 RESERVE STATION AUXILIARY TRANSFORMER

1) Station auxiliary power is supplied from the 115Kv substation through No. 1 Reserve Station Auxiliary Transformer.

2) The 115Kv substation bus voltage is regulated in discrete steps by action of a load tap changer. The setpoint is 120Kv ± 1 Kv. Response time of the LTC is approximately 1.5 seconds per tap change.

3) The 115Kv substation bus voltage can be "manually" adjusted by an operator utilizing the LTC controls in the substation if required.

4) Analysis indicates that the LTC will regulate the 115Kv bus voltage at 120Kv ±1 Kv with the 345Kv substation voltage varying between 336 Kv and 364 Kv.

5) A major system disturbance resulting in the tripping of the 115Kv substation or a failure of No. 1 Reserve Station Auxiliary Transformer will result in a unit trip requiring a shutdown without station auxiliary power other than that supplied to the ECCS buses by No. 1 AR Transformer or the emergency diesel generators.

6) Meters and computer analog points exist which will permit the operators to routinely monitor the 115Kv substation bus voltage and 4.16Kv bus voltage. Alarms exist which will alert the operator if unacceptable voltage levels are approached.

IV. CONCLUSION

It appears no technical reason exists which prevents operation with the unit station auxiliaries supplied from No. 1 Reserve Station Auxiliary Transformer. It must be recognized however, that a major 115Kv system disturbance or failure of No. 1 Reserve Station Auxiliary Transformer would result in a unit trip, while operating at full power, and subsequent shutdown without station auxiliary power other than that supplied to the ECCS buses from No. 1 AR Transformer or the emergency diesel generators.

6. Develop and provide for NRR review by September 12, 1983, administrative controls to assure that the 345kv and 115kv switchyard voltages remain above the minimum values necessary to assure their associated minimum operating voltages on the 4160 volt ac essential buses. The controls will include frequent voltage monitoring and operating procedures for actions to be taken by plant personnel in the event that either switchyard voltage falls below its minimum value.

RESPONSE

A Volume F Temporary Operations Manual change was issued on September 9, 1983 which superseded the previous Volume F change provided to our Project Manager in the Division of Licensing on August 24, 1983. A copy of the revised and expanded Volume F change will be provided to our Project Manager as an attachment to this response.

Copies of our System Operations Department dispatcher procedures for control of low and high system voltages are also being provided to our Project Manager for Staff review.

We will be prepared to discuss these procedures in detail at our meeting in Bethesda on September 13, 1983.

7. Conduct necessary confirmatory tests during the next refueling outage to demonstrate that, with an initial voltage equal to the minimum operating limit, all safety-related loads can be started and operated without activating the degraded voltage protection relays and thereby depending on the onsite Emergency Diesel Generators, and without exceeding any specifications on the safety-related equipment. A detailed description of your demonstration, including any tests and a summary of the test results, will be submitted to NRR for reveiw within 30 days following completion of any testing."

RESPONSE

A confirmatory test will be conducted during our next refueling outage current scheduled for February, 1984. A detailed description of the demonstration and test results will be submitted for NRR review.

8. Submit an interim special report on this event to NRR by September 12, 1983, describing: the sequence of events, unexpected equipment performance, justification of continued operation and corrective actions taken and planned. A detailed followup report will be submitted within 45 days of the date of this letter. Subsequent followup reports will be submitted as appropriate.

RESPONSE

I. Sequence of Events, Including Unexpected Equipment Performance

On August 1, 1983 the Plant was operating at 100% rated power, 553 MWE, 1670 MWth. Generator terminal voltage was at 20.94 Kv and station auxiliary loads were supplied by No. 11 Station Auxiliary transformer. No. 16 essential safeguards bus voltage was estimated to have been between 3960 volts and 3990 volts. No. 12 RHR SW pump and No. 14 RHR pump were in service on No. 16 bus for torus cooling.

At 0352, No. 14 RHR SW pump was started for torus cooling. The starting voltage transient was sufficient to trip the degraded voltage relays for No. 16 Bus. The sequence of events that followed is:

TIME	DESCRIPTION
03:52:03	Started No. 14 RHR SW pump for torus cooling. The starting voltage transient was sufficient to trip the degraded voltage relays for No. 16 Bus. Although voltage returned to above the trip setpoint within the allowable (10.0 sec) time delay, it did not get high enough to reset the relays.
03:52:14	No. 16 Bus (4KV Essential Safeguards Bus) transferred to No. 12 diesel generator source after the degraded voltage relays timed out. Non-essential loads were properly shed from No. 16 bus. The control room ventilation tripped into emergency mode due to the power transfer. As part of the normal load shed from No. 16 bus, the No. 12 Reactor Protection System (RPS) MG-Set tripped. Loss of #12 RPS MG-set resulted in a half-scram, start of standby gas treatment system, closure of secondary containment isolation dampers, trip of reactor building ventilation fans, closure of appropriate Group 2 primary containment isolation valves, closure of Group 3 primary containment isolation valves, and loss of other loads connected to the MG-set. These events are normal for a loss of #12 RPS MG-set.

TIME	DESCRIPTION

The transfer of No. 16 Bus caused the Uninterruptible MG-set to switch to DC drive and transferred Buses Y20 and Y30 to their alternate source. See Attachment 1. Thus, during the event, Bus Y20 was supplied from normal station auxiliary sources and Buses Y10 and Y30 were supplied from the Uninterruptible MG-Set.

When the Uninterruptible MG-set transferred to the DC power source, it failed to properly maintain regulation of its output frequency. This resulted in a variety of malfunctions of instrumentation and control systems.

The following effects were observed on plant instrument and control systems:

1. The 100" range Yarway reactor level indicators failed downscale. (All other reactor level indicators remained functional.)

2. The 'A' main feedwater (FW) control valve closed and locked in position. (Reactor level was maintained using the 'B' main FW control valve which remained in service and the low flow control valve which was placed in service.)

3. The total feedwater flow indication decreased from 6.8E6 LB/HR to approximately 6.0E6 LB/HR. (Not real flow change, indicator only.)

4. The turbine control valve cam position indication decreased from about 93% to 80%. (Not a real position change.)

5. The Standby Liquid Control (SBLC) tank wide range level indicator and pump discharge pressure indicator failed downscale. (This did not affect operability of the SBLC system.)

6. The Reactor Water Cleanup (RWCU) regenerative heat exchanger inlet pressure indicator and dump flow indicator failed downscale.

7. The Reactor Building vent wide range noble gas effluent monitors and one of the two off gas stack wide range noble gas effluent monitors exhibited erratic indication. (One reactor building vent plenum monitor and one off gas stack wide range noble gas monitor were unaffected.)

TIME	DESCRIPTION
	8. The reactor recirculation MG-set scoop tubes locked in position.
	9. The process computer tripped.
04:20	Normal source breaker for No. 16 bus was closed and diesel generator breaker opened by operators.
04:30	Operator transferred No. 12 RPS bus to an alternate source and reset RPS half-scram and primary containment isolation logic.
04:35	NRC was notified by phone of the Significant Event (SE) per 10CFR50.72.
04:48	By this time, operators had restored reactor building ventilation, restored shed loads, returned uninterruptible MG-set to AC drive and transferred instrument buses Y20 and Y30 to their normal sources. The FW flow indication and turbine control valve cam position indicator returned to pre-event values. The wide range noble gas effluent monitors resumed normal indication. Except for the following items, all indications and control functions returned to normal when the uninterruptible MG-set was returned to AC drive. 1. Internal fuses in the 100" Yarway indicators were found blown. Upon replacement of the fuses, the indicators operated properly. 2. The SBLC system instrument power supply was found to have a failed transformer. The power supply was replaced. 3. The RWCU system instrument power supply was found to have a failed transformer. The power supply was replaced.
04:52	Process computer was restarted.
05:25	'A' main feedwater control valve was manually reset and returned to operation.
05:42	Operators restored control room ventilation to normal mode.
09:40	Operators transferred No. 12 RPS Bus from the alternate source back to No. 12 RPS MG-set.

TIME	DESCRIPTION
13:20	No. 11 Recirc MG-Set scoop tube was reset manually after operational checks were performed.
13:25	No. 12 Recirc. MG-Set scoop tube was manually reset after operational checks were performed.

Investigation of the uninterruptible MG-Set and 'A' Feedwater Control valve malfunctions are continuing. A silicon controlled rectifier (SCR) and the DC tachometer on the uninterruptible MG set were replaced. Further testing on "A" FW Control valve is planned during plant shutdown.

Throughout the event the Reactor and Main Turbine Generator continued to operate under control at rated power.

II. Justification fo Continued Operation

Operation of the plant was maintained at rated power throughout the event.

It was determined to be safe to transfer the safeguards bus No. 16 to No. 11 Station Auxiliary transformer after observing and examining the following:

1. No. 12 diesel generator carried proper voltage while supplying safeguards bus No. 16, indicating that there were no physical or electrical problems with the bus network.

2. Prior to manual transfer, operators determined there were no target/flag indication of any protective relay operation on the 4KV switchgear with the exception of the degraded voltage target indication. This indicated no other electrical problems existed on the 4KV system.

3. The cause of the event was believed to be associated with No. 14 RHR SW pump. Work was in progress on the No. 14 traveling screen and although the bays are separated, something could have inadvertently found its way to the pump. Once lodged, a possible locked rotor condition could have existed on No. 14 RHR SW pump motor. This would have explained the degraded voltage indication found in the 4Kv switchgear.

Continued operation was then justified by the following:

1. Nothing occurred during the event that indicated a problem with safety system design or operation. The transfer itself functioned as designed.

2. The RHR SW pump No. 14 was subsequently tested and found to be operable. The pump was electrically and mechanically checked prior to testing.

3. The degraded voltage relays were checked and found to have the proper setpoint. It was orignally thought that their setpoints had

drifted in a conservative manner. (Conservative from the standpoint of protecting equipment from degraded voltage.)

4. Operating procedures were revised to assure that a similar degraded voltage transfer would not occur. These procedures accounted for the reset band of the degraded voltage relays.

5. During the event, when the uninterruptible MG set transferred to the DC power source, it failed to properly maintain regulation of its output frequency. This resulted in a variety of malfunctions of instrumentation and control systems including the 'A' Feedwater Control Valve. When the Uninterruptible MG set was returned to AC drive, instrumentation and control systems returned to normal. The 'A' Feedwater Control valve was reset and has operated properly since the event.

The Uninterruptible MG Set has been taken out of service for failure analysis and troubleshooting. Normal plant operation will continue with Panel Y10 receiving power from essential Motor Control Center (MCC) 133 via No. 11 Standby Instrument AC Transformer.

III. Corrective Actions Taken and Planned

An analysis was performed which established the proper minimum operating voltages on the 4160 volt essential buses that would not challenge the degraded voltage relays during worst case motor starting conditions.

Procedural changes were then made to maintain these operating voltages. These procedures define actions to be taken when essential bus voltage reaches an action point level. This action point level for operator response is ten volts higher than the established minimum operating voltages.

The process computer alarm points have been reset to provide a computer alarm at the action point level.

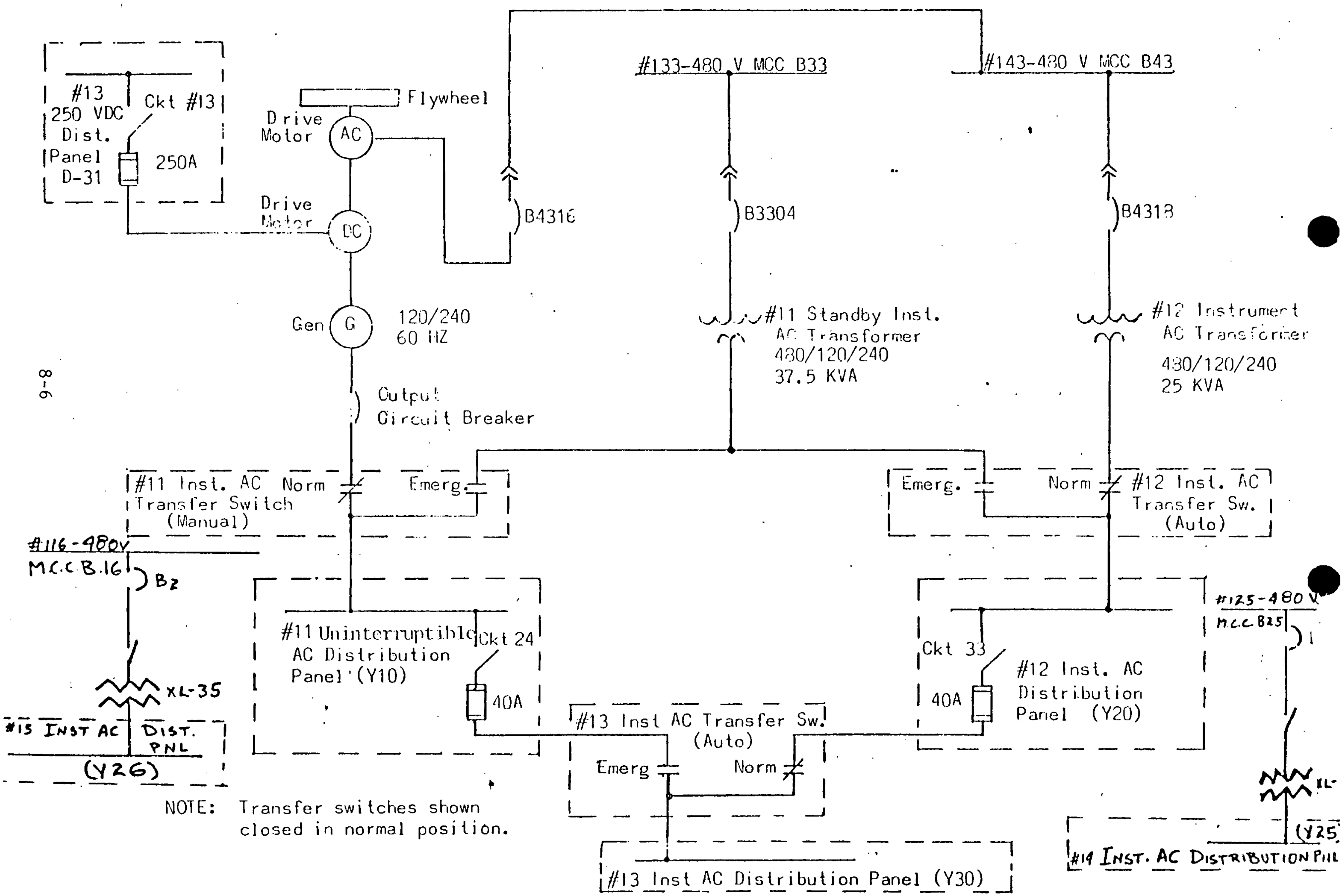
A NOTEPAD Response was issued to recommend that other utilities examine their undervoltage relay schemes to determine if a similar reset dead band could result in this type of event.

Examination of the Uninterruptible MG set speed regulator circuit showed a low anode to cathode resistance on the power silicon controlled rectifier (SCR). In addition the DC tachometer commutator and brushes were badly grooved. The SCR and a DC tachometer were replaced.

Future plans call for the consideration of the replacement of:

1. Degraded voltage relays with relays having a smaller reset dead band.

2. Rotary Uninterruptible Power System with a solid state system.


#13
250 VDC
Dist.
Panel
D-31
Ckt #13
250A
Flywheel
Drive
Motor
AC
Drive
Motor
DC
Gen
G
120/240
60 HZ
Output
Circuit Breaker
B4316
#133-480 V MCC B33
B3304
#11 Standby Inst.
AC Transformer
480/120/240
37.5 KVA
#143-480 V MCC B43
B4318
#12 Instrument
AC Transformer
480/120/240
25 KVA
#11 Inst. AC
Transfer Switch
(Manual)
Norm
Emerg.
Emerg.
Norm
#12 Inst. AC
Transfer Sw.
(Auto)
#116-480V
M.C.C.B.16
B2
XL-35
#15 INST AC DIST. PNL
(Y26)
#11 Uninterruptible
AC Distribution
Panel (Y10)
Ckt 24
40A
Ckt 33
40A
#12 Inst. AC
Distribution
Panel (Y20)
#125-480 V
M.C.C. B25
XL-
#13 Inst AC Transfer Sw.
(Auto)
Emerg
Norm
NOTE: Transfer switches shown
closed in normal position.
#13 Inst AC Distribution Panel (Y30)
(Y25)
#14 INST. AC DISTRIBUTION PNL

9. Submit a revision of your January 30, 1981, analysis of the adequacy of your station electric distribution system to NRR by December 31, 1983. We understand the revision will include a reevaluation of the design of your degraded voltage protection system and a reevaluation of your design assumption that all offsite power sources are degraded whenever the degraded voltage protection system is actuated. We further understand that the revision will include a separate analysis for your normal operation of supplying station auxiliary loads from the main generator via the No. 11 Auxiliary Transformer."

RESPONSE

We will submit a revision of our January 30, 1981 analysis of the adequacy of our station electrical distribution system which will include an analysis of operation from the No. 11 Auxiliary Transformer. This submittal will also include an evaluation of the degraded voltage protection system.

10. Perform troubleshooting and/or failure analysis of problems associated with the UPS MG Set and submit the results to NRR for review by September 12, 1983, including a description of your short-term and long-term corrective actions to improve the reliability of the UPS MG set.

<u>RESPONSE</u>

I. Troubleshooting

a. MG Set started on AC drive transferred to DC drive with attached load bank. Measurements taken on voltage and frequency, adjustments made on speed regulator gain setting.

b. Examined dc tachometer and found grooved commutator and brushes.

c. Measurements taken on the silicon controlled rectifier, SCR, in the power circuit of the speed regulator. Measurements showed low cathode to anode resistance.

d. Examine motor starter contacts which revealed a poor contact surface.

II. Short Term Corrective Actions

a. Replacement speed regulator circuit card ordered.

b. DC tachometer commutator machined, brushes replaced and tested satisfactory.

c. SCRs ordered.

d. Motor starter contacts cleaned.

e. Preventive Maintenance procedure revised to include closer examination of tachometer and motor starter contacts.

III. Long Term Corrective Actions

a. Replacement of rotary UPS MG set with a static inverter.

11. Reevaluate your response to IEB 79-27 in light of plant equipment performance during the August 1, 1983, event and submit the results of your reevaluation to NRR within 60 days of the date of this letter. Your reevaluation will also include consideration of a failure of the UPS MG set and the consequent loss of power to the instrumentation buses which it supplies.

RESPONSE

A reevaluation of our response to IEB 79-27 will be performed and reported to NRR by October 30, 1983 as requested.