SECTION 8

PLANT ELECTRICAL SYSTEMS

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SECTION 8 PLANT ELECTRICAL SYSTEMS

8.1 SUMMARY

Each main generator feeds electrical power at 20 KV through its isolated phase bus to the associated Generator Step Up Transformer. The power requirements for station and unit auxiliaries are supplied by a Main Auxiliary Transformer connected to the isolated phase bus, following practices that have been highly satisfactory for fossil-fueled and other nuclear units. Auxiliary power for startup, shutdown and normal backup is supplied from Reserve Auxiliary Transformers designated 1R and 2RS. Transformer 1R is the normal backup source for Unit 1 and is connected to the 161kV external power system. Transformer 2RS is the normal backup source for Unit 2 and is connected to the 345kV external power system. Bus ties are provided to allow crossfeeding should one transformer be out of service. Redundant offsite power sources are provided of sufficient capacity to supply all critical loads for either or both units. Each Safeguards bus has a preferred and alternate offsite source consisting of a Reserve Auxiliary Transformer and a Cooling Tower Substation Transformer, respectively. The Cooling Tower Substation sources are not large enough to also serve as a redundant startup source. Emergency backup power, to ensure continuity of supply for critical loads, is supplied from four onsite, quick-start Emergency Diesel Generators.

The function of the Auxiliary Electrical System is to provide reliable power to those auxiliaries required during any normal or emergency mode of plant operation.

The design of the system is such that sufficient independence or isolation between the various sources of electrical power is provided in order to guard against concurrent loss of all auxiliary power.

GDC 2 - Performance Standards

Those systems and components of reactor facilities which are essential to the prevention or to the mitigation of the consequences of nuclear accidents which could cause undue risk to the health and safety of the public shall be designed, fabricated, and erected to performance standards that will enable such systems and components to withstand, without undue risk to the health and safety of the public, the forces that might reasonably be imposed by the occurrence of an extraordinary natural phenomenon such as earthquake, tornado, flooding condition, high wind or heavy ice. The design bases so established shall reflect: (a) appropriate consideration of the most severe of these natural phenomena that have been officially recorded for the site and the surrounding area and (b) an appropriate margin for withstanding forces greater than those recorded to reflect uncertainties about the historical data and their suitability as a basis for design.

To satisfy GDC 2, all electrical systems and components vital to plant safety, including the Emergency Diesel Generators, are designed as Class I systems so that their integrity is not impaired by the Design Basis Earthquake, wind, storms, floods, or disturbances to the external electrical system. Power, control and instrument cabling, motors and other electrical equipment required for operation of the engineered safety features are suitably protected against the effects of either a Design Basis Accident, or of severe external environmental phenomena in order to assure a high degree of confidence in the operability of such components in the event their use is required.

<u>GDC 39 - Emergency Power for Engineered Safety Features</u>

An emergency power source shall be provided and designed with adequate independency, redundancy, capacity, and testability to permit the functioning of the engineered safety features and protection systems required to avoid undue risk to the health and safety of the public. This power source shall provide this capacity assuming a failure of a single active component.

To satisfy GDC 39, independent alternate power systems are provided with adequate capacity and testability to supply the required engineered safety features and protection systems.

The plant is supplied with normal, standby, and emergency power sources as follows:

a. The main source of auxiliary power during operation of either Unit is the Unit's generator. Power is supplied via the Main Auxiliary Transformer that is connected to the main leads of the generator.

b. Standby power required during startup, shutdown, and after reactor trip of either Unit is supplied from the Northern States Power Company's 161 KV and 345 KV transmission systems, via the plant substation through two independent connections from the substation to the plant.

c. Two emergency diesel generator sets dedicated to each Unit are connected to the engineered safety features (safeguards) buses to supply shutdown power in the event of loss of all other AC auxiliary power.

d. Emergency power for vital instruments and controls for each Unit is supplied from two 125 VDC systems for each unit. 01471873

The Emergency Diesel Generators are connected to the separate 4160 volt auxiliary system buses in each Unit. Each set is started automatically on a safety injection signal from its Unit or upon the occurrence of undervoltage on its corresponding 4160 volt bus. The Emergency Diesel Generator arrangement provides adequate capacity to supply the engineered safety features for the Design Basis Accident in one Unit, assuming the failure of a single active component in the system.

GDC 24 - Emergency Power for Protection Systems

In the event of loss of all offsite power, sufficient alternate sources of power shall be provided to permit the required functioning of the protection systems.

To satisfy GDC 24, the facility is supplied with normal, reserve, and emergency power to provide for the required functioning of the protection systems.

In the event of a Loss of Coolant Accident (LOCA) coincident with the Loss of Offsite Power (LOOP) event, emergency power is available from two Emergency Diesel Generators dedicated to each unit.

The instrumentation and controls portions of the protection systems will be supplied from the 125 VDC systems during the diesel startup period.

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8.2 TRANSMISSION SYSTEM

8.2.1 Offsite Transmission Grid Configuration

The output of the Prairie Island Generating Plant is delivered to a 345/161 KV Substation located at the plant site. Electrical energy generated at 20 KV is transformed to 345 KV by the Generator Step Up Transformers. A one-line diagram of the 345 KV connections for Units No. 1 and 2 is shown in Figure 8.2-2. 01395778

There are five transmission lines that connect the Prairie Island Plant to the transmission system. Two of the 345 KV transmission lines are connected directly to the Red Rock Substation and a third 345 KV transmission line is connected to the Hampton Substation. The Red Rock and Hampton Substations are connected to the Minneapolis, St Paul area high voltage grid. A fourth 345 KV transmission line is connected to the North Rochester Substation in southern Minnesota and from there, the line proceeds to the Bryon and Adams Substations and then through Iowa to Missouri where it is tapped several times to major Substations. 01395778

The basic scheme used in the 345 KV portion of the Substation is the breaker-and-one-half system.

The 161 KV portion of the Substation is a single bus arrangement. The 161 KV Substation is connected to 345 KV Bus 2 by 345/161/13.8KV No. 10 Transformer. The fifth transmission line is a 161 KV line which connects to the Spring Creek Substation and then supplies power to the Red Wing, Minnesota area.

Figure 8.2-3 shows the site arrangement of transmission lines and underground power cables. A single line diagram for the Cooling Tower and Plant (345/161KV) Substation is included on Figure 8.2-2. The criteria for spacing between lines are based on national standards for such lines.

8.2.2 Offsite Grid Reliability

Reliability considerations to minimize the probability of power failure due to faults in the network interconnections and the associated switching are as follows:

a. Redundancy is designed into the network interconnections for the units by having four transmission circuits into the 345 KV system and one transmission circuit into the 161 KV system. These systems are interconnected at the site and any one 345 KV circuit is capable of providing the full power requirements for the startup or shutdown of either Unit.

b. Physical separation of transmission lines is maintained on site as much as possible to provide isolation. The transmission line spacing in the vicinity of the site is greater than the height of the towers.

c. Transmission line design for lightning performance is based on less than one outage per 100 miles per year.

d. The substation switching arrangement provides nine 345 KV circuit breakers for six transmission line/generator outlets. This type of design is referred to as a breaker-and-one-half design, and includes two full capacity main buses. Dual simultaneous relay protection is provided for each bus and line/outlet. Breaker failure relaying protects for scenarios where the interrupting device fails to clear a fault.

   Operating characteristics of this design include:

   1. Any transmission line/outlet may be switched open under normal or fault conditions without interrupting another line/outlet.

   2. Any single circuit breaker or bus may be isolated for maintenance without interrupting power or protection to any line/outlet.

   3. Short circuits on a single main bus are isolated without interrupting service to any line/outlet.

   4. Failure of a bus side breaker will result in the loss of only one line/outlet until the failed component is isolated.

   5. Dual simultaneous relay protection provides coverage for failure of one set of protective relaying.

e. Design and construction of the 345 KV and 161 KV transmission lines exceed the requirements of the National Electrical Safety Code for heavy loading districts, Grade B construction.

With the above features, the probability of loss of more than one source of auxiliary power from credible faults is low, however, in the event of an occurrence causing loss of all the 345-KV and 161-KV connections, power for essential service is supplied from four onsite emergency diesel generators.

In the event that both Prairie Island Units trip simultaneously, the offsite supply to the safety features system would not be interrupted. The breaker-and-one-half design is such that the two unit trip event does not isolate auxiliary power supply points from the transmission lines serving the substation.

The adequacy of offsite power supply to the auxiliary safety sources in the event of a two unit trip is discussed below.

Voltage supplied to auxiliary systems from offsite sources after a two unit trip depends on many variables. The direction and magnitude of power flows due to system load, power transactions and pattern of on-line generation play a large role in post-trip voltage.

Studies using normal peak-load system steady state load-flow simulation show that loss of the maximum generation from Prairie Island (a 2-unit trip) can be sustained with adequate voltage. Offsite sources to auxiliary systems are not interrupted, and provide proper voltage to the safety equipment.

Key to this contingent performance ability are the spinning and standby reserves maintained by NSP and other MidContinent Area Power Pool (MAPP) member utilities.

These reserves total in excess of 15% of the MAPP peak load. (For example 1990 MAPP operating reserves totaled 3529 MW).

Contingent support immediately after loss of the Prairie Island Units is supplied by rotor inertia and governor action of other generating units throughout the interconnected eastern two-thirds of the United States and the eastern half of southern Canada. NSP derives this support over transmission tie-lines with capacity exceeding 3000 MW. After several minutes the MAPP spinning and standby reserve capability replaces the import from the interconnected systems.

No customer load interruption or break-up of NSP's transmission system is anticipated as a result of a Prairie Island two unit trip. The offsite supplies to the plant safety features therefore continue to operate without interruption.

Backup systems are in place to cover contingent system conditions which may exist prior to a two unit trip. An underfrequency load shed system is in use by all MAPP member utilities which would shed approximately 10% of the system load at each of three frequencies: 59.3 Hz, 59.0 Hz and 58.7 Hz. This shed of 30% of load is intended to restore a balance between load and generation and return system frequency to a proper level.

NSP has also installed an under-voltage tripping system to cover the multiple contingency events which could pose the threat of system voltage collapse. In the scenario of several prior contingencies, and a subsequent Prairie Island two unit trip, the adequacy of 345-KV offsite voltage source to plant auxiliary system is protected by automatic load shedding. This is intended to restore system voltage to a proper level.

Simulation of Prairie Island two unit trip event is performed using computer load flow models. NSP uses two types of load flow programs, one for modeled studies, and a second for analysis of real-time system conditions using telemetered voltage and power flow data. The computer models are representations of the transmission system electrical characteristics and components. Accuracy of the models are periodically verified by comparison with actual historical data. Further studies are performed to examine details of the dynamic conditions after the assumed loss of the Prairie Island Units.

8.2.3 Protection and Control for Interconnections

Each of the 161, 34.5 and 13.8 KV sources has both overcurrent and breaker failure protective relaying.

All 345, 161, 34.5 and 13.8 KV breakers are equipped with dual trip coils.

Each of the 345 and 161 KV feeders transmission line feeder breakers has primary, secondary and breaker failure protective relaying.

The DC control system in the substation consists of two completely independent 125 volt systems. Each system has its own battery, charger and fused distribution cabinet. One 125 volt system is used for primary relaying requirements, operation of breaker trip coil #2, backup supply to breaker charging motors and MOD control. The second 125 volt system is used for secondary relaying requirements, breaker controls, operation of breaker trip coil #1 and breaker failure relaying. 01395778

Controls for 1H2 and 1H4 13.8 KV Medium Voltage Switchgear Breakers (MVSB's) are in the Substation control house. DC control power for the cooling tower area 4.16 KV breakers is supplied by a single 48 volt battery located with the 4160 volt switchgear in the Cooling Tower Equipment House.

Under normal operating conditions the 13.8 KV breakers 1H2, 1H4 and 4160 volt breaker CT11-1, CT11-6, CT12-6 and CT12-7 are closed and the 4160 volt bus tie CT-BT 112 is open. Bus Tie breaker CT-BT 112 is normally maintained in the open position and can be manually closed so that either cooling tower area transformer can supply both 4160 V bus sections.

A 345 KV bus #2 Lockout, No. 10 Transformer Lockout, operation of either the 13.8 KV feeder overcurrent or ground detection relaying, Lockout of CT 12 Transformer, or Lockout of 2RS Transformer (if 8H12 is closed) will trip and lockout 1H2 - 13.8 KV MVSB and the 4160 volt source breaker CT12-7. 1H2 breaker failure relaying will also trip and lockout CT12-7.

With only CT11 Transformer feeding both 4.16 KV bus sections CT11 and CT12, breaker CT 12-7 is open and CT-BT 112 is closed. With a fault on bus section CT12, protective relays operate a lockout relay to trip and lockout breaker CT12-6, CT12-7 and CT-BT 112.

A phase or ground fault on 4160 volt feeder from CT12 Bus to Plant Safeguards bus 25 or 26 operates protective relays and trip 4.16 KV breaker CT12-6.

A 345 KV Bus #1 Lockout, CT1 Transformer Lockout, operation of either the 13.8 KV feeder overcurrent or ground detection relaying, Lockout of CT11 Transformer, or Lockout of 2RS Transformer (if 8H10 is closed) will trip and lockout 1H4 - 13.8 KV MVSB and the 4160 volt source breaker CT11-1. 1H4 breaker failure relaying will also trip and lockout CT11-1.

With only CT12 Transformer feeding both 4.16 KV bus sections CT11 and CT12, breaker CT11-1 is open and CT-BT 112 is closed, a fault on bus section CT11, protective relays will operate a lockout relay to trip and lockout breakers CT11-1, CT11-6, and CT-BT 112.

With a phase or ground fault on the 4160 V feeder from CT11 Bus to Plant Safeguard bus 15 or 16, protective relays operate and trip breaker CT11-6.

The No. 1 and No. 2 Generator Step Up Transformers are each provided with an over-undervoltage relay to protect the transformer against grounds or an overvoltage condition occurring on the transformer while it is energized from the 345 KV Substation and delivering station auxiliary load.

8.2.4 Onsite Interconnections

Three separate power systems are provided by the Substation to the Plant 4160 volt safeguards buses. An overhead 161KV transmission line from the Substation to the Plant’s 161/4.16KV 1R Transformer provides power to the Unit 1 4160 volt safeguards buses 15 and 16. An underground 35KV line from 345/35KV 2RS transformer in the substation to the Plant’s 35/4.16KV 2RY Transformer provides power to the Unit 2 4160 volt safeguards buses 25 and 26. Two underground 13.8 KV feeders from the 345/13.8 KV Cooling Tower Transformer (CT1) and the tertiary of the 345/161/13.8 KV No. 10 Transformer provides the power to the Cooling Tower Substation 13.8/4.16 KV transformers CT11 and CT12.

These transformers supply separate buses in the Cooling Tower 4160 volt switchgear that may be connected together by a bus tie breaker. Underground feeders from Cooling Tower Bus CT11 feed Unit 1 safeguards buses 15 and 16. Underground feeders from Cooling Tower Bus CT12 feed Unit 2 safeguards buses 25 and 26.

1R Transformer, 2RS Transformer, CT1 Transformer and No. 10 Transformer can be supplied power from any of the four 345kV transmission lines.

The 13.8 KV tertiary of 345/161/13.8 KV No. 10 Transformer is the source to 1H2 13.8 KV MVSB in the Substation. 1H2 13.8KV ACB is the source breaker for the underground feeder to the cooling tower area 13.8/4.16 KV CT12 Transformer. CT12 Transformer supplies 4.16 KV Bus Section CT12 through CT12-7, which is a 4.16 KV MVSB in the Cooling Tower Equipment house. 4.16 KV Bus Section CT12 feeds the Unit 2 Safeguards 4.16 KV Bus 25 or 26 through 4.16 KV MVSB's CT12-6 and 25-5 or 26-13, respectively.

345/13.8 KV CT1 Transformer is the source to 1H4 13.8 KV MVSB in the Substation. 1H4 13.8 KV MVSB is the source breaker for the underground feeder to the cooling tower area 13.8/4.16KV CT11 Transformer. CT11 Transformer supplies 4.16 KV Bus Section CT11 through CT11-1, which is a 4.16 KV MVSB in the Cooling Tower Equipment house. 4.16 KV Bus section CT11 feeds Unit 1 Safeguards 4.16 KV Bus 15 or 16 through 4.16 KV MVSB's CT 11-6 and 15-7 or 16-8, respectively.

8.2.4.1 Paths for Unit 1 Safeguards Trains

For Unit 1 there are four possible paths between the offsite transmission system and the safeguard 4160V buses. Each path is capable of providing the required power to shutdown the reactor and maintain it in a shutdown condition. These four paths are as follows:

- The first path is fed from the 161kv switchyard bus. This feeds the 1R transformer which in turn supplies power to buses 15 and 16.

- The second path is fed from the 345KV switchyard Bus 1. This feeds the 345/13.8KV Cooling Tower Transformer No. 1 which is connected via an underground cable run to the 13.8/4.16KV cooling tower transformer CT11. The secondary of this transformer feeds buses 15 and 16 through breakers CT11-1 and CT11-6.

- The third path is fed from the 345kv switchyard to transformer 2RS, transformer 2RY, breaker 2RYBT, breaker 12RYBT, breaker 1RYBT and then to buses 15 and 16.

- The fourth path is fed from the 13.8kv tertiary winding of the 345/161/13.8KV No. 10 Transformer. This 13.8kv feed supplies underground cable to 13.8/4.16KV cooling tower transformer CT12. From here is it fed through bus tie breaker CT-BT 112 to breaker CT11-6 and finally to buses 15 and 16.

8.2.4.2 Paths for Unit 2 Safeguards Trains

For Unit 2 there are four possible paths between the offsite transmission system and the safeguard 4160V buses. Each path is capable of providing the required power to shutdown the reactor and maintain it in a shutdown condition. These four paths are as follows:

- The first path is fed from the 345kv switchyard to transformer 2RS, breaker 2RSY, transformer 2RY and then to buses 25 and 26.

- The second path is fed from the 13.8kv tertiary winding of the 345/161/13.8KV No. 10 Transformer. This 13.8kv feed supplies underground cable to 13.8/4.16KV cooling tower transformer CT12. From here it is fed through breaker CT12-6 to buses 25 and 26.

- The third path is fed from the 161kv switchyard bus. This feeds the 1R transformer, breaker 1RYBT, breaker 12RYBT, breaker 2RYBT and then to buses 25 and 26.

- The fourth path is fed from the 345KV switchyard Bus 1. This feeds the 345/13.8KV Cooling Tower Transformer No. 1 which is connected via an underground cable run to the 13.8/4.16KV cooling tower transformer CT11. The secondary of this transformer feeds breaker CT-BT 112 to breaker CT12-6 and then to buses 25 and 26.

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8.3 AUXILIARY POWER SYSTEM

8.3.1 Design Basis

The auxiliary electrical system is designed to provide redundant electrically and physically separated buses for the safety feature loads for each unit. As shown in Figure 8.3-1, the redundant safety features loads (per Unit) are divided between these buses, with each bus fed (in emergency) from a different Emergency Diesel Generator. No paralleling or synchronizing of Emergency Diesel Generators is required.

Two normally open bus tie breakers are provided between each 4160V bus section of one Unit and the companion bus section of the second Unit. These tie breakers would be closed only during a station blackout as discussed under 8.4.4, or during maintenance, testing, or other manually supervised operations.

8.3.2 Description

The basic components of the plant electrical system are shown in Figure 8.3-1.

The plant's main generators serve as the main source of auxiliary electrical power to the non-safeguards buses during "on-the-line" operation of the plant. Power is supplied by a 20/4.16 KV three winding Main Auxiliary Transformer that is connected to the main leads from the generator via isolated phase bus connections having the same reliability as the main generator leads. Each safeguards bus is normally supplied from one of two possible offsite sources.

8.3.2.1 Load Transferring

During controlled startup, the non-safeguards 4160 volt auxiliary power buses are manually transferred without interruption from the Reserve Auxiliary Transformer to the Main Auxiliary Transformer (and in the reverse direction on shutdown), under supervision of synchronism check interlock relays.

Trouble in the reactor, turbine, main generator, Generator Step Up, or Main Auxiliary Transformer, calling for isolation of the Unit from the system, would automatically initiate a supervised fast transfer of station auxiliaries from the Main Auxiliary Transformer to the Reserve Auxiliary Transformer. In the event that the safeguards buses are subjected to an undervoltage condition, the logic attempts to transfer the safeguards buses to their respective alternate offsite sources, if available, either the Reserve Auxiliary Transformers or the Cooling Tower Transformers.

Assuming a normal successful transfer, the Emergency Diesel Generators would not start and their connecting circuit breakers would not close because the buses would be re-energized from the alternate offsite sources. In case of an unsuccessful transfer to the alternate offsite source, the associated Emergency Diesel Generators would automatically start, come up to speed and voltage, and close on to the safeguards buses.

All electrically operated circuit breakers used in the 4160 volt and 480 volt Auxiliary Electrical System are of the stored energy type to ensure reliable operation.

8.3.2.2 Load Sequencing

Starting of safety features loads is sequenced in five second steps to avoid momentarily overloading a power source by sudden application of too great a load. The control or logic equipment to accomplish this sequential loading consists essentially of programmable logic controllers (PLC) which have undergone extensive verification testing as outlined in NSP's letter to the NRC, (Reference 1). Control and logic systems are designed to ensure maximum reliability of the system within the safety requirements that the control scheme must provide.

8.3.2.3 4160 Volt Auxiliary System

The 4160 volt auxiliary system for each unit is divided into safety related and non-safety related buses. The non-safety related buses are arranged so that each bus can be supplied from its associated main generator through its Main Auxiliary Transformer or from the 345kV/161kV system through the Reserve Auxiliary Transformers. All 4160 volt auxiliaries are distributed between the 4160 volt buses in accordance with reliability requirements and diversity. For Unit 1, buses 11 and 12 serve large reactor auxiliaries (Reactor Coolant Pumps, Feedwater Pumps). Buses 13 and 14 serve general plant auxiliaries. Buses 21, 22, 23 and 24 serve similar functions for Unit 2.

The safety related (safeguards) 4160 volt buses 15, 16, 25 and 26, can be supplied from the 345 KV/161KV system through the Reserve Auxiliary Transformers and the Cooling Tower Substation Transformers, or from one each of the four Emergency Diesel Generators. Buses 15 and 16 serve engineered safety feature auxiliaries on Unit 1, and buses 25 and 26 serve similar functions on Unit 2.

8.3.2.4 480 Volt Auxiliary System

The 480 volt auxiliary system for Unit 1 consists of ten power centers, six of which serve non-safety related equipment. Five of the non-safety related centers are double-ended, consisting of a split bus, a bus tie break, and two 4160/480 volt transformers. The sixth center is single-ended, consisting of a single bus and transformer. For Unit 1, 480 volt power for engineered safety features and other essential plant loads is fed from load centers 111, 112, 121 and 122. These load centers are fed from step-down transformers connected to 4160 volt buses 15 and 16. Normal operation is with the normal feed transformer of a load center energized, and carrying the single bus normally associated with it.

For Unit 2 there are ten power centers, six of which serve non-safety related equipment. Five of the non-safety related centers are double-ended, consisting of a split bus, a bus tie break, and two 4160/480 volt transformers. 480 volt power for engineered safety features and other essential plant loads is fed from load centers 211, 212, 221, and 222. These load centers, are fed from 4160 volt buses 25 and 26. Normal operation is with the normal feed transformer of a load center energized, and carrying the single bus normally associated with it.

Alternate power sources for the 480V safeguards buses, from the same train of the opposite unit, are included in the design. These are used primarily for ease of maintenance during outages on the 4.16 KV buses, and are not required for operation. Each alternate source line-up consists of an incoming line compartment, and a 4160-480 volt transformer section. One alternate souce line-up per train is provided for use by either or both 480V safeguards buses.

NRC Bulletin 88-10, “Nonconforming Molded-case Circuit Breakers” and Supplement 1 to Bulletin 88-10 requested licensees to provide reasonable assurance that molded-case circuit breakers purchased for use in safety-related application without verifiable traceability to the manufacturer can perform their intended safety functions. Northern States Power responded to NRC Bulletin 88-10 as it applied to Prairie Island in References 2 and 3. In response to Supplement 1 to NRC Bulletin 88-10, as documented by Reference 3, Northern States Power reviewed and verified that the provisions of the bulletin were met and provided additional clarification on actions taken with respect to six nontraceable molded-case circuit breakers. The NRC Staff found the Northern States Power response to NRC Bulletin 88-10 and Supplement 1 acceptable in Reference 4.

8.3.3 Performance Analysis

The physical locations of electrical distribution system equipment are such as to minimize vulnerability of vital circuits to physical damage as a result of accidents.

Main and Reserve Auxiliary Transformers are located outside and are physically separated from each other.

Lightning arresters are used where applicable for lightning protection. All oil transformers located close to the plant are covered by water-spray systems to extinguish oil fires quickly and prevent the spread of fire. The transformers have oil catch basins and drains to remove oil from the transformer area in case of an oil spill or leak. Transformers are spaced to minimize their exposure to fire, water, and mechanical damage.

The design of the Auxiliary Electrical System capacity is based on computerized studies of loading under normal running, normal sequential starting, and emergency transfer of the system from normal to reserve source conditions.

System capacity is adequate to operate the plant in a safe manner under all normal conditions. Under emergency conditions, automatic load shedding and tripping of non-essential loads are provided in the transfer control system, prior to connecting safety features loads to the emergency diesel generators.

The adequacy of station electric distribution voltages was analyzed in accordance with Plant System Branch position PSB-1. The analysis demonstrated:

a. Station distribution system voltages remain acceptable under minimum and maximum expected values of grid voltage for motor starting and running

b. Undervoltage protection circuitry is not challenged with minimum expected values of grid voltage and component drift

The analysis results were used to establish operating guidelines which guarantee a minimum 4160V safeguards bus voltage of 94.8% to allow long term operation on offsite power without actuating degraded voltage protection relays (set at 95.5 ± .7%). Testing and analysis (Reference 19) have shown that all safeguards loads will operate properly at or above the minimum degraded voltage setpoint.

Sufficient protective devices, circuit breakers, and fuses, are provided and coordinated to assure isolation of faulted equipment with a minimum of disturbance to the rest of the system. Electrical coordination is also credited in the post-fire safe shutdown analysis described in procedure F5 Appendix E (incorporated by reference). 01452175

The design of the system is such that sufficient independence or isolation between the various sources of electrical power is provided in order to guard against concurrent loss of all auxiliary power.

Independence or isolation of supply to the various duplicated auxiliaries provided as engineered safety features is maintained so that a single failure does not result in a loss of more than one group of the plant's redundant engineered safety features systems. Arrangements and location of the components of the auxiliary power system, transformers, switchgear, cable runs containment vessel penetrations, etc., provides this isolation. A simple arrangement of buses is provided, requiring a minimum of switching to restore power to the bus in the event that the normal supply to that bus is lost.

Special attention has been given to the separation of cable trays, troughs, and channels, and the routing of cable trays to avoid fire hazards areas. Power cables are separated from control or instrumentation cables. Control and power cables for the engineered safety features system have a minimum separation between redundant circuits of 36 inches. Where closer spacing cannot be avoided, an approved barrier is placed between the circuits. Cable entrances into the control room, relay room, and Class I areas are sealed to prevent the entrance of smoke and fire from outside sources. In the D5/D6 Building cable and trays are routed in accordance with IEEE-384-1981. Refer to Section 8.7 for more detailed information on all separation requirements.

Two separated control trains are provided for redundancy in the engineered safety features system. This separation is maintained to preclude the possibility of any single incident causing both systems to become inoperative.

The supervised fast transfer of the auxiliary system or its components from the Main Auxiliary Transformer to Reserve Auxiliary Transformer is automatically controlled to assure a minimum interrupted time for power and a minimum effect on the system.

The 4160 volt switchgear and 480 volt load centers are located in areas which minimize their exposure to mechanical, fire, and water damage. This equipment is properly coordinated electrically to permit safe operation of the equipment under normal and short-circuit conditions.

The 480 volt motor control centers are located in the areas of electrical load concentration. Those associated with the turbine-generator auxiliary system in general are located in the turbine building. Those associated with the nuclear steam supply system are located in the Auxiliary Building.

The application and routing of control, instrumentation and power cables are such as to minimize their vulnerability to damage from any source. All cables are designed using conservative margins with respect to their current carrying capacities, insulation properties, and mechanical construction.

All engineered safety features power cable insulation and all power cables in the containment have fire-resistant sheathing selected to minimize the harmful effects of radiation, heat and humidity. Appropriate instrumentation cables are shielded to minimize induced voltage interference. Wire and cables related to engineered safety features and reactor protection systems are routed and installed to maintain the integrity of their respective redundant channels and protect them from physical damage. This wire is color-coded and routed in color-coded cable trays.

Supports for cable trays are designed in accordance with the tray manufacturer’s recommendation, based upon 100% tray load (corresponding to 40% cross-sectional fill) and calculated seismic loads. The number of conductors in a tray is limited according to factors recommended by the 1990 National Electric Code (NEC) or the cable manufacturer. Trays filled beyond 40% cross-sectional fill or the NEC recommendations are evaluated.

Cables in trays are derated for ambient temperatures.

8.4 PLANT STANDBY DIESEL GENERATOR SYSTEMS

8.4.1 Design Basis

The normal power sources for the safeguards buses are the 161-4.16/4.16 KV Reserve Auxiliary Transformer (Unit 1 1R), the 34.5/4.16 KV Reserve Auxiliary Transformer (Unit 2 2RY), and the redundant 13.8-4.16 KV Cooling Tower Substation buses (Unit 1 CT11 and Unit 2 CT12), as discussed in Section 8.2.1.

If the Reserve Auxiliary Transformers and the Cooling Tower Substation buses should fail, backup power is provided by two Emergency Diesel Generators in each unit sized and connected to serve the engineered safety features equipment of the unit. Each Emergency Diesel Generator is sized to start and carry the engineered safety features load required for the Design Basis Accident and concurrent loss of offsite power (LOOP).

In the event that an Emergency Diesel Generator fails to start, only one set of redundant safety features components would be lost in that unit. By means of later manual switching, safety features components on the bus associated with a failed Emergency Diesel Generator could be fed from the other Unit's Emergency Diesel Generator up to the capacity of the running engine, as discussed under 8.4.4. There is no single known component whose failure prevents both Emergency Diesel Generators in a Unit from starting.

Emergency Diesel Generator starting control is independent of the AC system except for the associated 4.16 KV bus voltage-detecting relay which is connected in a "fail-safe" manner to start the Emergency Diesel Generator on loss of AC power.

Unit 1 Emergency Diesel Generator equipment is located in separate heated rooms, protected from atmospheric conditions, in a Class I portion of the Turbine Building, permitting nearly ideal rapid-start conditions. The rooms are connected by a single access opening which is provided with a Class "A" fire rated door. The door, which is normally closed, is furnished with an extra-strong door closer equipped with a fusible link arm. Since the wall separating the two emergency diesel generators is parallel with the rotation of the diesel generator, it is incredible that a missile generated by the failure of one diesel generator will breach the wall opening.

Unit 2 Emergency Diesel Generator equipment is also located in separate rooms, protected from atmospheric conditions, in the Class I D5/D6 Building. These rooms are separated by a twelve inch thick reinforced concrete barrier. There are no wall openings directly between the two rooms.

8.4.2 Description

Each Emergency Diesel Generator, as a backup to the normal standby AC power supply, is capable of sequentially starting and supplying the power requirements of one of the redundant sets of engineered safety features for its reactor Unit. In addition, in the event of a station blackout (SBO) condition, each Emergency Diesel Generator is capable of sequentially starting and supplying the power requirements of the hot shutdown (Mode 3, Hot Standby in ITS) loads for its unit, as well as the essential loads of the blacked out unit, through the use of manual bus tie breakers interconnecting the 4160V buses as discussed in 8.4.4.

Unit 1 Emergency Diesel Generators (D1 and D2)

The Unit 1 Emergency Diesel Generators consist of two Fairbanks Morse units each rated at 2750 KW continuous (8760 hr basis), 0.8 power factor, 900 rpm, 4160 Volt, 3-phase, 60 Hertz. The 1,000 hour rating of each Emergency Diesel Generator is 3000 kilowatts. The 30 minute rating of each unit is 3250 kilowatts maximum. This figure is based on cooling water at a maximum temperature of 95°F and ambient air at a temperature of 90°F. The limitations imposed by the generator and the heat removal equipment limits the overall 30 minute rating of the system to 3250 kilowatts.

Each diesel engine is automatically started by compressed air stored at a pressure of approximately 250 psia. Two parallel solenoid admission valves deliver air simultaneously to a timed pilot air-distributor valve and an individual air-start valve located in each of the twelve cylinders. Starting air is thus admitted directly into the cylinder liners for fast, reliable cranking and starting. Adequate cranking effort is obtained with only six air valves. The additional six valves give increased starting reliability.

Each Unit 1 Emergency Diesel Generator has its own independent air starting system including a motor-driven air compressor, (powered from a 480 Volt emergency bus) and two accumulators each of sufficient capacity to crank the engine for 20 seconds. An interconnecting header with manual valving is provided between the starting system of the two engines, to allow the air accumulators of the opposite engine to be replenished. Cranking continues until the engine starts (speed over 250 rpm) or until a predetermined time limit (10-15 seconds) has elapsed, whichever occurs first. If an engine fails to start within the predetermined time limit, a “start failure” alarm is initiated and the engine control locks out, requiring manual reset.

Unit 2 Emergency Diesel Generators (D5 and D6)

The Unit 2 Emergency Diesel Generators consist of two tandem-drive units (gensets) manufactured by Societe Alsacienne de Constructions Mecaniques de Mulhouse (SACM), each rated at 5400 KW continuous (8760 hr basis), 0.8 power factor, 1200 rpm, 4160V, 3-phase, 60 Hertz. The gensets are radiator cooled independent of the plant cooling water system.

Each Unit 2 genset, has its own air starting system consisting of four independent subsystems, composed of a dryer, compressor (powered from a 480 volt nonsafeguards bus), and air receiver. Any two of the four air receivers will start the genset within ten seconds. This capability allows each Unit 2 genset to remain “available” to start and accept load within 10 seconds when only two of the four starting air receivers are charged to a pressure of ≥480 psig. (Reference 39 and Reference 44) 01423445

For each Unit 2 genset to be considered “operable”, any three of the four air receivers charged to a pressure of ≥480 psig are required. This ensures that the genset will start and accept load within 10 seconds and ensures the capability of the air receivers to provide a minimum of five cranking cycles without recharging. This is an air receiver sizing requirement. (Reference 38 and Reference 44) 01423445

Cranking continues until the genset starts (based on lube oil pressure) or until five seconds has elapsed, whichever occurs first. If the genset fails to start within the five seconds, a “start failure” alarm is initiated and the genset control locks out, requiring manual reset.

The two air-start subsystems for each engine of the genset have interconnecting piping to the fuel injection stop jacks on the other engine. This piping is pressurized only on an overspeed trip by a valve device which opens at the overspeed setpoint. The piping to the opposite engine stop jack is to assure that both engines shutdown on an overspeed trip without depending on the governor shutdown solenoid valves. Each engine has two separate overspeed trip devices.

Units 1 and 2 Emergency Diesel Generators (D1, D2, D5, D6)

Control voltage for the diesel starting/control system is obtained from 125 volt DC System 11 for D1, and DC System 12 for D2. Similarly, control voltage is obtained from DC System 21 for D5, and DC System 22 for D6. Figures 8.5-1a, 8.5-1b, 8.5-2a and 8.5-2b show the 125V DC distribution for Unit 1 and Unit 2. For D1 and D2, loss of DC control power after the engine starts will not stop the engine or interfere with its operation. Direct current power must be restored to stop the engine electrically. For D5 and D6, engine speed control will fail to the hydraulic droop governor so that the speed/frequency depends on busload per the hydraulic governor droop curve. If only the control circuit for the genset control is lost, it will keep on running; however, if the entire DC source to the Vertical Panel for all circuits is lost, the diesel will keep running and cooling fans and fuel booster pumps will be lost. The operator would have to manually stop the genset.

To ensure rapid start, each diesel generator is equipped with electric heaters which furnish heat to the engine cooling water and engine lubricating oil when the engine is shut down. Motor driven circulating pumps for cooling water and lube oil operate continuously when the engines are shut down.

For each EDG, an audible and visual alarm system is mounted on the control panel located adjacent to the associated engine. An “engine trouble” alarm is sounded in the main control room whenever an alarm is sounded on the local engine generator control panel. A main control room alarm also sounds if the controls at the engine are not set on “automatic”, or DC control power is lost.

Sufficient fuel is stored in the day tank for each Unit 1 Emergency Diesel Generator for up to two hours operation at full load. Sufficient fuel is stored in the day tank for each Unit 2 EDG for at least 60 minutes of operation at the level where oil is automatically added to the day tank based on the fuel consumption at a load of 100% of the continuous rating of the EDG plus a minimum margin of 10% per ANSI N195-1976. Fuel from interconnected storage tanks can be transferred to the day tanks by electric pumps for operation of any single Emergency Diesel Generator up to two weeks. See Section 10.3.13 for further information.

Redundancy and flexibility are provided by two engineered safeguards buses, serving safety related equipment, associated with each of the two Units, connected so that each safeguards bus is served from a different Emergency Diesel Generator (four total). The sequence in which the safeguards loads are picked up by the Emergency Diesel Generators, and the delay times required, are discussed in the following loading description:

Each Emergency Diesel Generator is automatically started by either of the following events:

a. Undervoltage, which envelopes loss of voltage (including LOOP), or degraded voltage on the associated 4160 Volt buses (buses 15 and 16 for D1 and D2, and buses 25 and 26 for D5 and D6 respectively. Automatic starting of the Emergency Diesel Generators is initiated by a modified 2-out-of-4 voltage relay scheme on each 4160 Volt bus to which the Emergency Diesel Generator is to be connected.

b. Initiation of a Safety Injection Signal (both of the affected Unit’s Emergency Diesel Generators start on this signal).

Undervoltage Logic

Relays are provided on buses 15, 16, 25 and 26 to detect undervoltage and degraded voltage conditions. The undervoltage setpoint is 75 $\pm$ 2.5% with a time delay of 4 $\pm$ 1.5 seconds. When an undervoltage condition exists on any of these buses, the associated PLC based Load Sequencer automatically initiates the following steps for the affected bus.

a. Trip source breakers to the bus.

b. Load rejection of designated loads on bus.

c. If the alternate offsite source is available, attempt to restore power from the alternate source.

d. If the alternate offsite source is not available, or does not successfully restore the bus, the associated Emergency Diesel Generator auto starts.

e. The EDG breaker closes onto the bus after the EDG has met established frequency and voltage criteria (within 10 seconds of receiving start signal).

f. Load restoration by sequenced steps at 5 second intervals.

If an SI signal is received during an undervoltage condition, the EDG is started and steps c and d above are not performed.

If an SI signal is present and the Emergency Diesel Generator is supplying power to the bus when an undervoltage occurs, its breaker is not tripped in item a. above. The bus remains powered from the Emergency Diesel Generator, and there is no load rejection or load restoration.

Degraded Voltage Logic

The degraded voltage setpoint is 95.5 $\pm$ 0.7% with time delays of 8 $\pm$ 0.5 seconds and 60 $\pm$ 3 seconds. The upper limit to the setpoint has been established to preclude unnecessary actuations of the voltage restoration scheme at the minimum expected grid voltage. Analysis has shown that the 8 second delay is adequate to account for normal transients, such as voltage dips from the starting of large loads, and is longer than the time required to start the Safety Injection pump at minimum voltage. This first delay annunciates that a degraded voltage condition exists. The second delay of 60 seconds allows the degraded condition to be corrected by external actions within a time period that will not cause damage to the operating equipment. With degraded voltage on any of the four safeguards 4160V buses, the associated PLC based Load Sequencer automatically initiates the following steps after the 60 second delay.

a. Auto start the Emergency Diesel Generator and trip the offsite source breakers to the bus.

b. Load rejection of the designated loads on the bus.

c. Close the breaker to the Emergency Diesel Generator once it has met established voltage and frequency criteria (within 10 seconds of receiving start signal).

d. Load restoration by sequencing loads at 5 second intervals.

If a SI signal is received during the 60 second degraded voltage time delay, the above logic is immediately actuated by the Load Sequencer with SI loads added during the last step, item d. Except for auto starting the Emergency Diesel Generator, that is a function of the SI signal. 01416450

In both the undervoltage and degraded voltage scenarios described above, after voltage is re-established on the subject 4160 Volt bus, either from an offsite source or from an Emergency Diesel Generator, the Emergency Diesel Generator, if started (see discussion under 8.4.2), continues to run (loaded or unloaded) until manually shut down. The 480 Volt buses are immediately energized at the same time as the 4160 Volt bus from which it is fed.

Motors and loads which are operating or connected prior to the loss of voltage condition, that were not shed either automatically or manually during the time of voltage loss, and whose start signals are sealed-in would automatically restart or be re-energized upon return of bus voltage.

Motors not running prior to the loss of voltage condition would not start upon restoration of voltage, until subsequent manual or automatic action is initiated.

Load Sequencer Out of Service

With properly aligned 480V loads, the offsite sources have been analyzed to verify that a load sequencer failure will only affect the ability of the associated EDG to automatically power its respective safeguards loads following a LOOP independent of, or coincident with, a Design Basis Event.

Emergency Diesel Generator Loading

Three 25 HP Waste Gas Compressors are supplied, two fed from Emergency Diesel Generator D1 and one fed from Emergency Diesel Generator D2. One waste gas compressor is included in Step 1 of the load sequence for Emergency Diesel Generator D1 and one waste gas compressor is included in Step 1 of the load sequence for Emergency Diesel Generator D2. (Reference 43)

Three air compressors (121, 122, 123) feed into a common Instrument Air header which, in turn, supplies Instrument Air for both Unit 1 and Unit 2. Compressor 121 is fed from Emergency Diesel Generator D1, via Unit 1 480 Volt Bus 111. Compressor 122 is fed via Unit 1 480 Volt Bus 121 from Emergency Diesel Generator D2. Compressor 123 is fed via Unit 2 480 Volt Bus 211 from Emergency Diesel Generator D5.

Instrument Air is not essential for plant safety during a DBA, however, for nonsafeguards reasons, it is desirable to maintain Instrument Air if possible under this condition, one compressor is adequate for both units. Assuming either Unit 1 Emergency Diesel Generator (D1 or D2) is operating, either Air Compressor 121 or 122 can be assumed to be operating. Similarly, if Emergency Diesel Generator D5 is operating, Air Compressor 123 can be assumed to be operating.

Safeguards MCC's and their associated motor operated valves are energized simultaneously with the 480V safeguards busses except for the pressurizer heaters MCC's which are energized on Step 6 of the Load Restoration Sequence.

Loading on Emergency Diesel Generators is analyzed for a "worst case" condition as represented by a Safety Injection signal coincident with a complete loss of offsite power. (References 41 and 43) A "small break" LOCA that was sufficient to initiate automatic Safety Injection (SI) action would represent the same inrush KVA load on the Emergency Diesel Generator. If the break is so small that automatic SI is not initiated, manual action would be required as soon as the operator is aware of the break. Manual action would represent loads less than or equal to that analyzed in the calculations.

A small break would represent considerably less running load on the RHR Pump and possibly less on the SI Pump, but a longer running time for the SI Pump.

Emergency Diesel Generator Design and Qualification

The redundant onsite standby power sources and their corresponding distribution systems are arranged in the Prairie Island plant to meet all the requirements of Safety Guide 6.

Emergency Diesel Generators D1 and D2 were sized per AEC Safety Guide 9, Paragraph C-2, which requires the predicted load seen by an EDG not to exceed the smaller of either the 2000 hour rating or 90% of the 30 minute rating. The D1/D2 2000 hour rating is unknown. The continuous rating, which bounds the 2000 hour rating conservatively, is 2750 KW. The D1/D2 30 minute rating is 3250 KW, and 90% of the 30 minute rating is 2925 KW. Therefore, the conservative limit of 2750 KW is placed on D1/D2 predicted loads.

Analyses of maximum predicted loading for transient (Reference 43) and steady state conditions (References 36 and 42) show predicted loads are less than the conservative limit of 2750 KW. Therefore, D1 and D2 continue to meet the loading guidelines of paragraph C-2 of Safety Guide 9. Preoperational testing was performed on D1 and D2 in accordance with paragraph C-3 of Safety Guide 9.

With reference to Paragraph C-4 of Safety Guide 9, tests performed on a prototype of the Unit 1 Emergency Diesel Generator and subsequent calculations indicated that the speed limitations listed in Safety Guide 9 are met by Prairie Island Unit 1 Emergency Diesel Generators D1 and D2.

With reference to voltage variations, the prototype tests and subsequent calculations and surveillance testing indicate that the first inrush seen by the diesel when starting both the safety injection pump and the nonrejected loads that are connected to the EDG supplied bus can cause the voltage to decrease in excess of the 75% of nominal as stated in Safety Guide 9, and not be restored to normal within a maximum of 40% of the step duration (2 seconds). This voltage dip occurs on the first step of load application to the Emergency Diesel Generator and this exception to Safety Guide 9 does not degrade the reliability of the safety features in the plant for the following reasons:

1. Integrated SI testing history shows that < 3 seconds (60% of 5 seconds) is achieved. This is within the guidelines of Reg. Guide 1.9, Revision 2 utilized for D5/D6.

2. The Load Sequencer time interval is controlled by an internal digital clock in the Programmable Logic Controller driven Load Sequencer. This provides a very high degree of accuracy and repeatability in sequence timing. This lessens the needed margin between recovery from the dip and the end of the load step.

3. Historical data shows that the voltage returns to 100% well within five seconds as discussed below, assuring that excitation returns to normal, and full voltage is available for starting equipment at the beginning of the second load sequence step.

Engine speed under loading condition is difficult to predict accurately, but momentary speed drop during predicted inrush conditions will reach 90% with recovery in 2 to 4 seconds. Actual performance verification data is available from the Pre-Operational Surveillance Test results. Surveillance tests (SP1083) have shown 100% voltage recovery within three seconds.

The Unit 2 Emergency Diesel Generators (D5 and D6) meet the requirements of Reg. Guide 1.9, Revision 2, except portions of the 1984 Edition of IEEE 387 were implemented in the factory testing instead of the 1977 revision (NSP letter to NRC, September 9, 1989, Reference 5). These two diesel generators are rated at 5400 KW continuous. Analyses of maximum predicted loading for transient (Reference 41) and steady state conditions (References 36 and 42) show predicted loads are less than the conservative limit of 5400 KW. Thus the guidance of Reg Guide 1.9 paragraph C2 is satisfied. Testing has proven that the loading capabilities required by Reg Guide 1.9 paragraph C4 are also satisfied. 01469847

8.4.3 Performance Analysis: Loss-of-Coolant Accident and Loss of Offsite Power

Situations in which the high head safety injection pumps and the Emergency Diesel Generators would be simultaneously required are limited to the loss of either primary or secondary coolant from one Unit, concurrent with the loss of offsite a-c power. In the event of an accident requiring safety injection in one Unit, accompanied by loss of offsite power, the sequence of automatic operations is as follows:

a. A safety injection signal is derived from SI actuation circuits;

b. Reactor and turbine both trip;

c. When the reactor coolant pressure has fallen below 700 psi, the accumulators attached to the cold legs of loops A and B discharge their contents of borated water into the Reactor Coolant System;

d. The Emergency Diesel Generators start and upon loss of offsite power, as sensed by voltage relays, the load sequencers connect each Emergency Diesel Generator to its safeguards bus;

Upon receipt of a command signal, the Emergency Diesel Generators start. Within ten seconds, the EDG is up to speed and ready to accept load. As a result of continuing undervoltage on the buses, designated breakers then close, placing the EDG on the buses which feed the engineered safety features equipment (see discussion under 8.4.2). The load sequence on each Emergency Diesel Generator would be:

Step 1:	Safety Injection Pump and 480 V buses
Step 2:	Residual Heat Removal Pump
	Containment Spray Pump
Step 3:	121 Cooling Water Pump (Unit 2 only)
Step 4:	Component Cooling Water Pump
	2 Fan Coil Units
Step 5:	Auxiliary Feedwater Pump (Unit 1 Train B, Unit 2 Train A)
	1 Air Compressor (except Unit 2 Train B)
Step 6:	Pressurizer Heaters
	EDG Auxiliaries (Unit 2 only)
Step 7:	Control Room Chiller
	Chiller Water Pump

The time delay between starting the various components is long enough to allow the drive motors to approach synchronous speed (5 seconds or until voltage recovers, whichever is longer) as described in Section 8.4.2. The engines for the emergency diesel driven cooling water pumps are direct-connected to the pumps and operate independently of the Emergency Diesel Generators. Charging pumps are not necessary, and have not been included in the automatic starting sequence.

The configuration and operation of the Safety Injection System during the injection and recirculation phases of mitigation of a loss of coolant accident are described in Section 6.2.

In addition to the double ended break of a main reactor coolant pipe, all other less severe ruptures of the Reactor Coolant System require the operation of the engineered safety features system to an extent which depends upon the size of the rupture. Very small breaks cause expulsion of the reactor coolant at a rate which may be accommodated by operation of the charging pumps alone.

The double ended rupture of a main reactor coolant pipe remains the most severe of all of these accidents in terms of required operation of the engineered safety features system, and thus it is used together with a loss of auxiliary AC power as the basis for determining the requirements of the Emergency Diesel Generator capacity and, with a shutdown on the second unit, for determining the cooling water requirements, as described in Section 10.

8.4.4 Station Blackout

A Station Blackout (SBO) exists when there is a Loss of Offsite Power (LOOP) and concurrent loss of both of a unit's Emergency Diesel Generator sources. An SBO is assumed to occur on only one Unit of a two unit site, in accordance with Reg. Guide 1.155. Prairie Island meets the SBO rule of 10CFR50.63 (June 21, 1988) and the related guidance of Reg. Guide 1.155 (August, 1988). Prairie Island is classified as a four hour plant (four hour SBO duration) based on criteria contained in Reg. Guide 1.155 and NUMARC-8700 (References 32 and 33). In accordance with Reg. Guide 1.155 and NUMARC-8700, it has been demonstrated by testing that alternate AC (AAC) from the non-SBO unit's Emergency Diesel Generator is available and the interconnecting bus ties can be manually closed within ten minutes of the realization that an SBO condition exists to provide power to the required loads on the SBO unit (References 34 and 35). Analysis has shown that the AAC has sufficient capacity to supply the required loads for the non-SBO unit plus the required loads of the SBO unit for the required four hour SBO duration (References 32, 33, and 36) and that adequate condensate inventory is available to provide decay heat removal for the four hour SBO duration (References 32, 33, and 37). Additional coping analyses for other plant systems are not required for the SBO unit per Reg. Guide 1.155 and NUMARC-8700 due to the alignment of AAC to the SBO unit within ten minutes of the realization that an SBO condition exists (References 32 and 33).

EDG Loading criteria:

Because of the low probability of either an SBO or DBA occurring, the simultaneous occurrence of a DBA and SBO is not credible. NUMARC 87-00 provides the loading criteria for an EDG in the non-SBO unit cross-tied to the SBO unit and requires the EDG to carry: (1) the loss of off-site power safe shutdown loads on the non-SBO unit, and (2) the SBO loads on the SBO unit for the required coping duration. Reference NUMARC 87-00 Appendix J Question and Answer B.3.

These loading conditions are analyzed in Reference 36 for each EDG and each EDG is found to be loaded within its continuous rating.

SBO Loads:

Typically during an SBO, once the power is available to the SBO unit through the bus ties, equivalent equipment would be operated in the SBO unit as under a LOOP. Notable exceptions are that the SBO unit's EDG auxiliaries would not be operated, nor would the 121 Cooling Water Pump for a Unit 2 SBO. This condition is more conservative for the SBO unit than operating the "essential" SBO equipment as required by NUMARC because it includes more load than the essential SBO load.

8.4.5 Non-Safeguards Standby Diesel Generators

Non-safeguards 4.16 KV Buses 31, 41, 32 and 42 are normally supplied from Normal Buses 13, 23, 14 and 24 and their offsite sources, respectively. Buses 31 and 41 serve 480V Buses 310 and 410 respectively which have bus ties to form a double ended load center. Similarly, 480V Buses 320 and 420 are supplied by 4.16KV Buses 32 and 42. These 480V buses serve a variety of non-safeguards loads including plant process computers Uninterruptable Power Supplies, Non-safeguards station battery chargers, turbine generator AC auxiliaries, and miscellaneous Normal motor control center loads. The Bus 31/41 Load Centers are backed up by diesel generator D3, and Bus 32/42 Load Centers are backed up by diesel generator D4.

Diesel generators D3 and D4 consist of General Motors Electromotive Division units which were converted from MP-45 peaking units to emergency standby service. They are rated 2500 KW continuous (2750 KW peak), 0.8 power factor, 900 RPM, 4.16KV, 3-phase, 60Hz. They are radiator cooled with closed cooling,and utilize DC electric starting motors. DC power for engine starting, field flashing, and control is supplied from 125V DC Non-safeguards Systems 31 and 42. The diesel generators are capable of being manually run and synchronized onto the Normal 4.16KV plant buses from their respective control panels in the 31/41 and 32/42 Bus rooms. They are normally left in auto standby with the coolant and lube oil partially heated with a keep-warm system.

Both the 31/41 and 32/42 Load Centers have a load shedding and restoration scheme which will operate in the case that voltage is lost on a 480V bus. If both 480V buses in a load center lose power, then the diesel generator is given a fast start signal, source breakers are tripped, and the diesel comes up to speed and voltage after which the loads are sequenced back on the buses. Each diesel generator also has the capability to test the associated load-shedding and restoration scheme without actually tripping any loads.

8.5 DC POWER SUPPLY SYSTEMS

8.5.1 Safeguards 125 Volt DC System

The safeguards 125 VDC Electrical Power System for each unit consists of two independent and redundant safety related DC electrical power subsystems (Train A and Train B). 125 VDC Subsystems 11 and 12 serve Unit 1 and 125 VDC Subsystems 21 and 22 serve Unit 2. Each subsystem consists of one 125 VDC battery, battery charger, and associated distribution equipment. The configurations of the safeguards 125 Volt DC Systems for both Units are shown in Figures 8.5-1a, 1b, 2a, and 2b.

The 125 VDC Systems supply instrumentation, control, and motive power to safety related equipment. Redundant safety related equipment is divided between the two DC subsystems associated with each Unit such that loss of one DC subsystem does not affect redundant circuits.

The 125 VDC Systems and their components have a Safety Related quality assurance classification. The 125 VDC Systems are qualified to allow operation during and following a Safe Shutdown Earthquake. Specific components were tested or qualified for seismic events as described in Section 7.9.

The battery, battery charger, transfer switches and main panels for each of the 125 VDC Subsystems are located in their associated subsystem's battery room. The four battery rooms are located in a Design Class I area of the Turbine Building on the 695′ elevation as depicted on Figure 1.1-4. Two access routes per room are provided for personnel safety. The access between adjoining battery rooms is through openings in the reinforced concrete block walls. Each of these openings is furnished with a counterweighted gravity sliding Class "A" fire door provided with dual fusible links, one located on each side of the common concrete block wall. Fire dampers are provided in the ventilation ducts.

A detailed description of the safeguards 125 VDC Systems, including associated alarms, indications, procedures, maintenance, surveillance, and test procedures was provided to the NRC in Reference 20 in response to Generic Letter 91-06, Resolution of Generic Issue A-30, "Adequacy of Safety Related DC Power Supplies."

8.5.2 Safeguards Batteries

There are four safeguards batteries, one per 125 VDC Subsystem. The batteries temporarily assure a continuous source of DC electrical power to the DC System in the event of the loss of AC charging power until the AC power to the chargers is restored. The batteries also assist with supplying DC loads when the associated charger cannot supply the total DC load.

The batteries are flooded vented lead acid storage batteries. Each battery consists of 58 cells nominally. The batteries have a nominal rated capacity (to 1.75 volts per cell) of 1800 amp-hours at an 8 hour discharge rate.

One battery charger is in service on each battery so that the batteries are always at full charge in anticipation of a loss of AC power. This ensures that adequate DC power is available for starting the Emergency Diesel Generators and for other emergency uses. Once AC power is restored to the battery charger, it will resume powering the DC system loads and charge the battery.

Each battery has been sized to carry expected shutdown loads following a plant trip, and a loss of AC battery charging power for a period of 1 hour without battery terminal voltage falling below the required minimum. For each battery system, the minimum terminal voltage is that required to maintain the operability of all components required to operate during a design basis event (Reference 21). Battery sizing determination was also done using the methodology of IEEE-485 as guidance and takes into account minimum expected electrolyte temperature and margin for battery aging (Ref. 21). Major loads with their approximate operating times on each battery as well as minimum terminal voltage for each battery are provided in the referenced calculations (Ref. 21). 01407637

For Station Blackout, as discussed in section 8.4.4, Prairie Island is categorized as a four hour plant. However, Prairie Island has demonstrated that Alternate AC can be aligned within 10 minutes. Therefore, no coping assessment is required per NUMARC 87-00 Section 7.1.2. The safeguards 125 VDC battery on the SBO unit will provide DC power to support actions on the SBO unit for aligning the Alternate AC source to the SBO unit during the 10 minute timeframe and will power the one division of safeguards battery chargers. The battery sizing load profile stated in the previous paragraph bounds the battery performance load profile for Station Blackout. 01407637

8.5.3 Safeguards Battery Chargers

There are five safeguards battery chargers, one per 125 VDC Subsystem plus one portable battery charger. The battery chargers are supplied from the associated safeguards 480 Volt AC System MCC. The battery chargers supply DC electrical power to the connected loads while maintaining safeguards batteries fully charged during normal operation when the AC charging power is available except as allowed by Tech Specs. During transient or accident conditions, the battery chargers are the primary source of DC power when AC charging power is available.

Each of the four stationary battery chargers has been sized to recharge its associated partially discharged battery from a voltage of 105 VDC within 24 hours, while carrying its normal load.

Each battery charger has a nominal rated DC output of 400 amps with an adjustable current limit set under 315 amps at 130 VDC. Both float and equalize voltage are adjustable. The charger supply rating is 90 amps at 480 VAC while supplying 300 amps.

The battery chargers normally operate in float condition supplying power to the connected loads and charging power to their associated battery. Each battery charger has a three phase AC input circuit breaker and a two pole DC output circuit breaker. The battery chargers function to give desired output regardless of whether the battery is connected. The rectifier section of the battery charger ensures that the AC supply system does not become a load on the battery.

One portable battery charger can provide backup service in the event that one of the four stationary battery chargers is out of service. If the portable battery charger is substituted for one of the stationary battery chargers, then the requirements of independence and redundancy between subsystems are maintained.

The battery charger AC input transfer switches and DC output isolation switches allow switching of the normal DC power source from the stationary battery charger to the portable battery charger. These AC input transfer break-before-make switches prevent paralleling the portable and the stationary battery chargers.

8.5.4 Safeguards Distribution Equipment

The DC fused disconnect switches connect the battery to the Safeguards DC panels while protecting downstream loads from the potential fault current of the battery.

The DC load transfer switches allow switching the power sources to selected loads from the 125 VDC Subsystem of one Unit to the same train subsystem on the other Unit. These are break-before-make switches so that it is not possible to parallel the DC subsystems of both units during switching operations.

The main distribution panel for each DC subsystem provides power to loads throughout the plant.

8.5.5 Instrumentation, Controls, and Alarms

Control room alarms are provided for 125 VDC System grounds, undervoltage, fire doors, special exhaust fans, and general trouble. In addition, control room alarms and status indication are provided for several 125 VDC System parameters on the Plant ERCS.

Local indications for battery amps and panel volts are provided in each battery room.

The system operates ungrounded with ground fault detectors provided. With this type of arrangement, two grounds are required (one in the positive line and one in the negative line) before any of the system protective devices would operate. Occurrence of a ground of either polarity of sufficient magnitude, will cause control room alarm. This provides an opportunity for trouble-shooting.

8.5.6 Battery Room Special Exhaust Fans

The Battery Room Special Exhaust Fans (Unit 1: 11 and 12; Unit 2: 21 and 22) provide exhaust flow from the Battery Rooms to prevent the buildup of a combustible concentration of hydrogen gas in the battery rooms. The two fans for each Unit operate in parallel drawing exhaust through a common duct from the Unit's two battery rooms and discharging into a common duct which exhausts to the atmosphere. The battery room special exhaust fans are not required for accident mitigation.

8.5.7 Inspection and Testing

The station batteries and other equipment associated with the battery systems are accessible for inspection and testing. Battery maintenance, surveillance testing, and discharge testing is performed in accordance with the recommendations of the manufacturers and the plant Tech Specs. Battery charger maintenance and testing is performed in accordance with the recommendations of the manufacturers.

8.6 INSTRUMENTATION AND CONTROL AC POWER SUPPLY SYSTEMS

The configurations of the Instrumentation and Control AC Power Supply Systems for both Units are shown in Figures 8.5-1a, 1b, 2a, and 2b. Each Unit has four inverters that each supply one Panel that is dedicated to one Reactor Protection and NIS Channel. These Panels are also referred to as Instrument Buses. Each Unit also has two inverters that each supply one Panel that is dedicated to one train of Event Monitoring and other critical loads.

Each inverter contains an associated rectifier permitting the inverter to be normally fed from an AC source with instantaneous non-interrupted transfer to the DC system on loss of rectifier or AC supply. 01316490

Power supplied to the Instrument Buses is provided by the uninterruptable power supply (ups) which includes an automatic static transfer switch and a manual bypass switch in addition to the inverter. The automatic static transfer switch is designed to transfer the Instrument bus load from the inverter, if it fails, to the AC source through a bypass breaker.

The availability of control power to the engineered safety features trip signals is continuously indicated by means of indicating lights on the engineered safety feature panels and loss of control power for the engineered safety features actuation signals is annunciated in the control room.

A 3-phase 208/120 Volt AC “minimum interruptible bus” is provided on each unit. This bus is identified as Panel 117 on Unit 1 and Panel 217 on Unit 2. These panels are fed from a 480 Volt safeguard bus via a safeguard MCC. Various important AC instrument and control loads that can tolerate an infrequent short interruption (approximately 10 seconds) are fed from these Panels. Inverter loads are transferred to these panels when the inverter fails or must be removed from service for maintenance.

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8.7 CABLES AND RACEWAYS

8.7.1 Cable Derating

Current ratings of all the cables used in this plant are based on the values specified for the type of cable used, by IPCEA, NEC, or by the individual cable manufacturer. Power cables are installed in ladder type cable trays. They are installed with only a single layer of cables per tray and clamped in the ladder to ensure that a specified spacing exists between these cables to ensure that air cooling is available. Alternatively, the manufacturer's cable derating based upon random fill is utilized, and the cable installation maintains spacing which provides margin from the assumed random fill.

Control cables are grouped in the trays with random lay, and the ampacity rating for these cables is based on the load of the control circuits involved. NEC derating factors are appropriately applied for multiple conductors in conduit, or multi-conductor cables in tray.

All original construction Power Control and Instrument Wire and Cable used on safeguards related circuits in the plant was purchased and qualification tested from manufacturers certifying that the insulation used on these conductors, including splicing material, would perform satisfactorily and not be appreciably degraded when exposed to the following environmental conditions:

Normal Temperature (40 years)	90°C (194°F) conductor temperature
Emergency Temperature (48 hours)	138°C (280°F)
Pressure	46 psig
Relative Humidity - Normal	70%
Relative Humidity - Emergency	100%
Radiation	5×10^7 Rads
Containment Spray	Dilute solution of Boric (Acid 2000 - 3000 ppm of Boron) adjusted to pH of 9.0 to 9.5 with Sodium Hydroxide
Fire	Successfully pass the so-called "Philadelphia Electric Flame Test" or its equal.

Cables, relays, and control devices supplied by P.S.&E were temperature qualified as follows:

a. Cable and wire - 280°F (138°C) - tested for a minimum of two hours at this figure.

b. Relays and control devices - 178°F (70°C).

All new cable installed after original construction is qualified for the environment it is used in.

8.7.2 Cable Routing

The following categories are those to which the term “Power Cable” shall apply:

4160 volt feeders
480 volt feeders
120/208 volt main feeders and motor feeders
125 volt DC main feeders and motor feeders
125 volt DC subfeeders that are rated 30 ampere or higher

The following categories are those to which the term “Control Cable” shall apply:

120 volt AC and 125 volt DC metering
120 volt AC and 125 volt DC relaying
120 volt AC and 125 volt DC interlocking, indication and controls
120 volt AC and 125 volt DC annunciation
125 volt DC subfeeders with a continuous rating of 25 amperes or less

The term “Instrumentation Cable” shall apply to all cables that are used for low level circuits. The following categories are some of the areas to which this will apply:

Computer input and output signals
Thermocouples
RTD’s
Nuclear instrumentation and monitoring
Electronic control and recording devices
Transducer output signals

Mixing of power cables with control or instrument cables in the same tray is not permitted. Whenever a control and/or instrument cable tray and a power tray are in the same stack, the power tray is located in the top tier. Non-safeguard trays installed in stacks are spaced vertically with a minimum of 12″ bottom to bottom in all areas. However, Class IE trays have a minimum bottom to bottom dimension between trays of 15″ or 36″, depending on adjacent groupings. Class IE trays containing instrument, control, or power cables have a minimum horizontal separation between redundant circuits of 36″. Redundant circuits are not permitted in the same tray or conduit. If closer spacing than 36″ cannot be avoided an approved barrier must be placed between the circuits. Cable trays are routed to avoid a fire hazard area, such as oil storage rooms, oil tanks, etc., whenever possible. When this cannot be done, the cable tray system is protected by fire resisting barriers. Whenever possible, a wall or floor has been introduced between trays carrying redundant safeguard circuits.

Class IE cables for each of the two units in the plant are divided into six(6) basic groups consisting of the four Reactor Protection/NIS (colored) Channels and “A” and “B” redundant trains. Minimum spacing between these groups are maintained as follows:

1. Redundant A & B Trains	-36″ Horizontally (tray rail to tray rail) and Vertically (tray bottom to tray bottom)
2. Reactor Protection/NIS Channels	-36″ Horizontally (tray rail to tray rail) and Vertically (tray bottom to tray bottom)
3. Spacing Between any Reactor Protection/NIS Channel and any redundant A or B Train	-36″ Horizontally (tray rail to tray rail) and 15″ Vertically (tray bottom to tray bottom)

In items 1, 2, and 3, horizontal dimensions indicate clear air space between adjacent side rails. Vertical dimensions are tray bottom to tray bottom.

In item 3, redundant channels and trains are as follows:

Train A and the White and Blue Instrument channels, are redundant to Train B and the Red and Yellow Instrument channels.

In item 3, minimum clear air spacing between bottom of upper tray and top of lower tray is 9″ which allows a maximum 6″ tray siderail for the 15″ vertical spacing. This minimum vertical spacing would also apply between a Class IE Tray and a Non-Safety System Tray.

Lack of separation between a single train and any one channel of Reactor Protection/NIS is allowed as long as the channel has the same power supply as the train. There must not be a lack of separation such that both trains, two channels, or one train and two channels are affected by an uncleared fault.

Where separation is not attainable, protective barriers are provided.

Barriers are required where mutually redundant trays cross. The barriers extend to each side of the protected tray by a distance equal to approximately three times the widest tray involved in either system. Barriers are provided in areas where non-safeguard trays may cause common mode involvement between two or more mutually redundant safeguard systems, and the mutually redundant trays are not separated by more than three times the sum of the widest trays involved in each interaction.

Cable and raceway separation and segregation within the D5/D6 Building and Fuel Oil Storage Area conform to the requirements of IEEE 384-1981 as modified by NRC Regulatory Guide 1.75. Deviations from the requirements contained in those documents are shown to be acceptable and meet the intent of IEEE 384/RG 1.75 through analysis. Cable and raceway interconnections between the D5/D6 Building and existing plant facilities, including direct buried cable, duct runs and other raceway systems, as well as all cables and raceways routed within existing plant facilities, are separated and segregated in accordance with the requirements contained in the balance of this section as a minimum.

Safety related Train B cables are routed from the D5/D6 Building to the plant's Class I corridor through the Turbine Building, a Class III structure. These cables are enclosed in a steel structure to afford them Class I protection. This enclosure is designed as a Class I structure and provides protection from seismic and jet impingement forces. Analysis addressed other concerns, such as cable derating (8.7.1), tornado winds, missiles and fires.

8.7.3 Cable Tray Sharing

Every effort has been made to install safety related cables in their own trays. However, there may be isolated cases where non-safety related cables may be installed in the same trays with safety related cables. Non-safety related cables are not routed with cables of one safety-related system and then routed through its mutually redundant system.

8.7.4 Fire Protection

Fire Protection is discussed in Section 10.3.1. 01484954

8.7.5 Cable and Cable Tray Markings

Each tray section of the cable tray system has an identifying code indicated on the drawings and the same identification is stenciled on the tray after it is installed. This stenciling is applied on each section of the tray whenever the code changes. Any tray that is continuous through walls or floors has the identifying code stenciled on both sides of the wall or floor. Cable trays assigned to safety related circuits are also color coded. This coding is accomplished by a strip of colored plastic tape 2″ wide by approximately 3″ long affixed to the tray near the stencilled identifying number. Conduits carrying safety related conductors are similarly color coded with a wrap of colored tape affixed to each end of the conduit and on either side of the wall or floor it passes through. Straight portions of the conduit have this tape affixed at suitable intervals. Each multi-conductor control or instrument cable has a 1″ diameter brass identifying tag at each end carrying the cable number, which is affixed on to the outer jacket of the cable.

Safety related control cables have a colored strip applied to the jacket approximately 1 foot long at intervals of approximately 10 feet.

Cable color coding consists of 6 colors, based primarily on 6 sources of electrical supply.

The first two supplies consist of Train “A” and Train “B”. This may be 4160V AC, 480V AC, 240V AC, 120V AC or 125V DC. These AC supplies are fed directly from either offsite sources or Emergency Diesel Generators D1 and D2 for Unit 1, and from D5 and D6 for Unit 2. The DC Sources are fed from 125 VDC systems 11 and 12 for Unit 1, and from 125 VDC systems 21 and 22 for Unit 2.

The remaining 4 supplies consisting of 120V AC for instrument and reactor protection channels are fed from 4 separate inverters.

All cables associated with safeguards related equipment are color coded.

a. Train “A” supplies and controls are color coded “Orange”.

b. Train “B” supplies and controls are color coded “Green”.

c. Reactor protection and nuclear instrumentation systems (supply and control) listed as Channel I are color coded “Red”.

d. Reactor Protection and N.I.S. (supply and control) listed as Channel II are color coded “White”.

e. Reactor Protection and N.I.S. (supply and control) listed as Channel III are color coded “Blue”.

f. Reactor Protection and N.I.S. (supply and control) listed as Channel IV are color coded “Yellow”.

Power Supplies to the 4 inverters must originate from either Train “A” or Train “B”, White and Blue inverters are fed from Train “A” sources (either AC or DC) and Red and Yellow inverters are fed from Train “B” sources (either AC or DC).

If an engineered safeguards circuit is either Train A or Train B it can be easily distinguished from a reactor protection channel due to color coding.

If the circuit in question is an instrument channel entering a logic matrix with 2 or 3 other similar channels to form two safeguards action trains (“A” or “B”) by means of 2 out of 3, 2 out of 4, or similar logic means, that channel bears the same color code as the instrument bus (inverter) supplying it. AMSAC AFW actuation logic takes exception to this criteria, due to its required diversity of power.

Color coding is not intended to spell out the individual usage of each cable. The metal tag at the end of each cable carries a number distinctive to that one cable and by checking drawings this number can be used to find the exact usage of each cable.

Color coding was established as an easy means of maintaining the specified separation between 6 systems or sets of control, namely Train “A”, Train “B” and 4 instrument channels.

8.7.6 Relay Room Arrangement

The Safeguards Relay Racks and Reactor Protection Relay Racks are located in the Relay Room. The Safeguards and Reactor Protection Relay Racks are separated into “A” train and “B” train groups. Each train is in a common line-up with an approximate 5′-0″ aisle between groups.

The cable routing in this room is primarily in cable trays. The separation provided is in accordance with the previously stated separation criteria, except that one train is not allowed to interact with one channel even if the channel has the same power supply as the train.

8.7.7 Panel Wiring Separation

Control board switches and associated lights are furnished in modules. Modules provide a degree of physical protection for the switches associated lights and wiring.

The control board layout is based on making it easy for the operator to relate the control board devices to the physical plant and to determine at a glance the status of related equipment. This is referred to as providing a functional layout. Within the boundaries of a functional layout, modules are arranged in columns of control functions associated with separation trains defined for the Reactor Protection and Engineered Safeguards Systems. Teflon covered wire is generally used within the module and between the module and the first termination point.

The interface between the control board wiring and field wiring is made in terminal board cabinets one level below the control board. Teflon covered cables with connectors are provided for control board to terminal board cabinet interconnection. These cables are secured to metal supports to ensure separation of the cables consistent with the separation afforded by the front panel layout.

Redundant components are located in separate racks which are shown on Figure 7.8-1, which also shows the general arrangement of the control room.

Separation between redundant relay and terminal block cabinets is accomplished by using a separate cabinet for each train of components. Where redundant cabinets are placed side by side, the solid metal side walls of each cabinet provides the separation requisite.

Redundant Local Racks, Panels, and Control Stations used with Safeguards Systems are either separated by 3 feet of air space or an appropriate barrier is placed between the redundant components.

Instruments used with Safeguards Systems are either separated by a minimum air space of 36″ between mutually redundant devices or are mounted on independent racks separated by a minimum clear air space of 36″.

Cables entering redundant Local Racks, Control Stations Instrument Stations, Relay Cabinets, and Terminal Cabinets are designed to meet “Cable Separation” Criteria discussed in Section 8.7.2 “Cable Routing”.

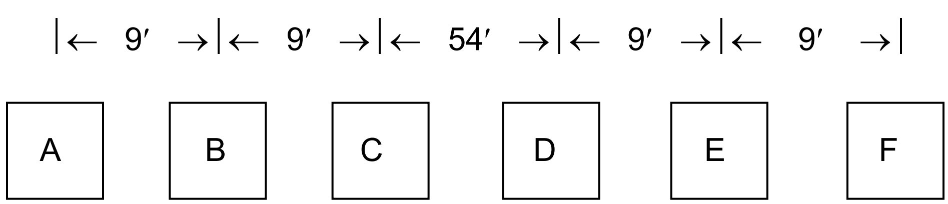
Control Modules on the Control Boards in the Main Control Room, have a minimum center-to-center separation of 4-1/2″. Such controls are completely enclosed in a Fire Resistant housing. Cables are connected to these modules with plug-in metal connectors and the cables are insulated and jacketed with Teflon. The criteria for minimum separation between redundant cable is 4-1/2″ except in cases where redundant cables enter the same Control Module where center-to- center separation is 3-1/4″ and except for cases of reduced separation that have undergone technical evaluation (Reference 13).

Panels containing safety related components have redundant counterparts located in separate cabinets or isolated areas within cabinets. This includes such devices as 4160 V undervoltage transfer relays and automatic permissive starting sequence relays; emergency diesel generator protection and control relays; D.C. Distribution Panels; and Terminal Block Panels for redundant safety related wiring to main control board.

8.7.8 Electrical Penetrations

Electrical penetrations entering the Reactor Building are subdivided into 6 basic groups:

Approx. Dimensions:



Each of the six groups has provision for 12 penetrations. The configuration in each group is three wide by four high. Each penetration in each group is spaced 2′-0″ center to center from any penetration in its group.

Groups A, B and C are located in one quadrant of the containment vessel with groups D, E, and F located in another quadrant approximately 54′-0″ apart.

Each group of penetrations in each quadrant is separated by a distance of approximately 4′-0″ to any adjacent penetration in any other group.

Each penetration in a group has a specific circuit function, e.g., Nuclear Instrumentation, Instrumentation and Control, Low Voltage Power, and Medium Voltage Power. In addition, each group of penetrations is assigned an Engineered Safeguards Train and Reactor Protection Channels as follows:

Group A - Normal circuits

Group B - Normal and Channel II circuits

Group C - Normal, Train “A” and Channel III circuits

Group D - Normal, and Train “B” circuits

Group E - Normal, Train “B” and Channel I circuits

Group F - Normal, Train “B” and Channel IV circuits

Cables passing through the air annulus between the reactor building and the containment building are segregated into the six basic groups as shown above and the same relative spacing between the six groups is maintained, as the cables pass through this air annulus.

When control and instrumentation connections between cables within the containment and the penetration connections are made at terminal blocks, exposed connections are covered with environmentally qualified materials suitable for the LOCA environmental conditions.

8.7.9 Annulus Cable Supports

All electrical cables in the annulus are provided with support systems of various methods.

Generally, the cables are supported by tiers of cable trays that are supported by structural members bearing on the external support concrete and tied back to the shield building. Power cables are clamped to the cable tray system with enough slack allowed at both ends so as to accommodate differential movements between the two buildings without interaction. Control cables are not clamped to the cable tray system and slack has been allowed at both ends.

The large 5000 volt cables used for the reactor coolant pump are supported somewhat differently. A supporting framework is clamped to the penetration nozzle (part of the containment vessel) to provide a rigid support for the cables at the outboard end of the porcelain bushings. The cables have approximately 18″ of slack prior to entering the embedded conduit in the shield building.

Annulus lighting system cables are all fully supported in conduit, which is fastened only to the shield building by clamps.

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8.8 INSPECTION AND TESTING

Historic Background for Class I Electric Equipment:

Inspection and testing at vendor factories and/or during construction were conducted to demonstrate the following on all Class I electrical equipment:

a. All electrical assemblies operate within their design ratings;

b. All components are properly mounted;

c. All metering and protective devices are properly calibrated and function correctly;

d. All connections are properly made and the circuits are continuous. Operational testing of the normal and standby power systems were conducted under conditions which simulate the loss of offsite power conditions. This testing demonstrated the following:

   1. All essential loads can be operated in the proper sequence for each Design Basis Accident condition with normal power for essential loads available;

   2. The relaying and control system can detect a loss of external power and, with the buses dead, start and load the standby power sources;

   3. The standby power sources can provide sufficient power for an adequate time interval.

Historic Background for D1/D2 Qualification and Testing:

The essential requirements of generator sets for nuclear power plant protection include positive start, rapid acceleration and load acceptance with acceptable voltage drop and fast recovery to rated voltage. To obtain more information related to these requirements with the 3000 KW Unit 1 emergency diesel generator sets (D1 and D2), the following tests were conducted:

a. Start, Parallel and Load Acceptance

   Arrangements were made to isolate a block of power house engines and suitable resistive load from factory operations for these demonstrations.

   Automatic equipment was set up to synchronize the test generator set with the power house engines. The synchronizer signal simultaneously opens the power house engine breakers, and closes the test generator set breaker connecting 3000 KW resistive load.

b. Motor Starting

Motor starting tests included:

1. Across line starting 2000 HP motor
2. Across line starting 1250 HP motor
3. Across line starting 2000 HP and 1250 HP motors simultaneously
4. Across line starting 2000 HP and 1250 HP motors with 1000 KW initial resistive load.
5. Simultaneous start of 3000 KW generator set and 2000 HP motor
6. Simultaneous start of 3000 KW generator set and 1250 HP motor
7. Simultaneous start of 3000 KW generator set, 1250 HP motor and 2000 HP motor
8. Locked rotor tests of 2000 HP and 1250 HP motors.

Demonstrations of motor start capabilities were conducted with unloaded motors. However, it is believed that the data obtained permits accurate prediction of starting similar motors with specified loads.

c. Instantaneous Overload Capability

With the engine producing 3000 KW on a resistive load bank, an additional 1000 KW resistive load was added for 7-1/2 seconds duration. These demonstrations showed that the system would accept the additional load and recover to rated frequency and voltage during the overload condition. The purpose of this demonstration was to show capability of accepting overload surges which may occur when a large motor “locks in” during the starting cycle.

d. Reliability Test

Test information for the Prairie Island Unit 1 Emergency Diesel Generators consists of the information obtained from the prototype tests performed in the manufacturer's plant on September 13 and 14, 1968. The various tests performed are the same as those listed in b. above. The first test consists of cross-the-line starting of a 2,000 horsepower motor. Test figures indicated that at initial inrush the voltage dipped to a figure approximately 55% of normal. The locked rotor KVA of this 2,000 horsepower motor was approximately 11,000 KVA. The manufacturer's curves supplied with the Prairie Island generator indicates that for a starting KVA of 11,000 the voltage dip can be expected to reach 50% of rated. Calculations for the Prairie Island diesel generators indicate that the initial in-rush seen on either generator is approximately 6,800 KVA and is the worst condition.

Curves for the D1/D2 generators indicate that for an inrush of 6,800 KVA the initial voltage dip will be to approximately 62% of normal and will recover to 100% of normal within 1-1/2 seconds. The inrush KVA imposed on the factory engine during the prototype test was approximately 1-1/2 times that calculated for the Prairie Island engines. Because the prototype tests indicated that a larger load than anticipated at Prairie Island could be safely started and brought up to speed, and no difficulties were expected with the Prairie Island engines.

Another of the tests performed on the prototype consists of cross-the-line starting of both a 2,000 and a 1,250 horsepower motor. This represents an in-rush of approximately 18,000 KVA. Voltage dip at this point was approximately 40% of rated and full recovery to normal voltage was delayed until the in-rush reduced to approximately 8,000 or 9,000 KVA. The test indicated the motors could be started and accelerated to speed. Testing as indicated was more severe than anything that can be predicted for the Prairie Island units.

In addition to the performance requirements of a satisfactory nuclear power plant protection system, reliability is an extremely important aspect. To prove the generator set, arrangements were made to demonstrate its reliability.

The generator set was direct connected to a water rheostat. The system was adjusted to 3000 KW load and suitable controls attached to effect the following sequence:

1. Start unit and accelerate it to rated speed and load.

2. Maintain 3000 KW load for five minutes.

3. Stop generator set without an idling or cooling off period.

4. Allow to stand for 1 hour, 55 minutes permitting temperatures to drop to the keep warm level.

5. Repeat 1, 2, 3, and 4 above through 100 consecutive cycles.

The prototype unit started each time with no failures. Each start was accomplished in 10 seconds or less. At end of the test, the unit was disassembled for inspection and was found to be in excellent condition.

Based on these 100 successful starts the probability of success (reliability) in starting the Emergency diesel generator within 10 seconds after initiation of the Start Signal is calculated to be 0.977 at a 90% confidence level. See Figure 8.8-1.

The Confidence Level is the probability that the calculated reliability is no less than the actual reliability. In other words, an increase in confidence level will add conservatism to the calculated reliability. This is necessary since the failure data sample is small (no failures in 100 starts). Also, the Calculation ($r=e^{-\lambda t}$, λ=Failure Rate, t=Mission Period or Cycle, λt=Failures/Test) was based on the exponential distribution of failures. This was an acceptable assumption until sufficient failure data is obtained which proves that the failures fit a distribution other than the exponential distribution.

Additional failures per start data were accumulated during the weekly emergency diesel generator tests. Starting each of the two diesel generators once a week accumulated an additional 200 starts in 23 months. This added to the 100 prototype engine starts represents data accumulated on 300 starts.

The acceptance test consisted of a 100 hour run at full (3000 KW) load. Subsequent plant tests were run to establish that the total and incremental blocks of load could be adequately started and maintained.

These tests have established the reliability and capability of the emergency diesel generators to provide their design function.

The Auxiliary Electrical System is tested at regular intervals during the life of the plant to demonstrate the capability of the system to provide sufficient power to the essential loads.

Since the emergency diesel generators are utilized as standby units, readiness is of prime importance. Readiness can best be demonstrated by periodic testing which, insofar as practical, simulates actual emergency conditions. The testing program is designed to test the ability to start the system as well as to run it under load for a period of time long enough to bring all components of the system into equilibrium conditions, to assure that cooling and lubrication are adequate for extended periods of operation. Full functional tests of the automatic circuitry are conducted on a periodic basis to demonstrate proper operation.

If the number of tests were increased to possibly 300, it was felt that the calculated reliability could be raised to 99% based on an anticipated failure rate of two or three in 300 starts.

Northern States Power Company accumulated this additional failures per start data on D1/D2 during the initial preoperational and startup test phase of Prairie Island Unit #1 startup. This data when added to the 100 prototype engine starts represents data accumulated on 300 starts.

The Unit 1 emergency diesel generator preoperational testing program included tests that:

1. Verified that the diesel generator's control, power and auxiliary systems can be normally maintained at a ready operating condition.

2. Verified that the various control switches in the diesel generator rooms activate the engine stopping relay.

3. Verified that the diesel operators can be started and controlled from the diesel generator rooms.

4. Verified that the diesel generators can be started and controlled manually from the control room G-1 panel.

5. Verified that the diesel generators automatically trip from the various engine trip signals and the alarms do occur, but does not trip from these signals if the MCA relay is closed.

6. Verified that the diesel generators can be paralleled with the NSP interconnected system and operated at various loads for a two week period. This test also included fuel consumption tests.

7. Verified that the diesel generators can carry a load of 3250 kilowatts for 30 minutes.

8. Verified that the diesel generators start when initiated by the undervoltage relay scheme on each 4160 volt bus to which the diesel generator is connected.

9. Verified that the diesel generator performance upon loss of the largest single load during emergency operation, does not adversely affect either of the diesel generators. These tests involved loading the diesel generators as outlined in Table 8.4-1 of FSAR Amendment 19, tripping of the largest single load, and measuring the voltage and frequency disturbance. This test also verified the proper loading sequence and include pumping of water to the vessel with the RHR pumps and the safety injection pumps.

The above tests were part of the Preoperational (Preop) Test Program for D1/D2 and the results are available in the Prairie Island Plant Preop Test File. All subsequent starting and testing is documented and becomes part of the plant surveillance file.

Historic Background for D5/D6 Qualification and Testing:

The Unit 2 Emergency Diesel Generators (D5/D6) underwent the following factory tests conducted by the manufacturer, SACM. This testing fulfilled the requirements for qualification testing delineated in Reg Guide 1.9, December 1979, and IEEE-387 with two principle exceptions, discussed in NSP's letter of September 29, 1989 (Reference 5) to the NRC, and accepted by their letter of January 31, 1990 (Reference 7). The first exception is utilizing portions of the 1984 edition of IEEE-387 instead of the 1977 edition invoked by Reg Guide 1.9. The second was 70 start and load acceptance tests, (item b. below) in place of the prescribed 300. The basis of this lesser number of start tests is summarized in item d. below.

a. Load Capability Test

The genset was started and run until system temperatures were at equilibrium. The generator set was then loaded to 110% of nameplate load for a continuous period of two hours. The generator set was then loaded to 100% of nameplate load (5400KW) for a continuous period of twenty two hours. Finally, the generator set was tested for loss of load transient response, which verified that engine overspeed values remained within acceptable parameters.

b. Start and Load Acceptance Test

The genset was started thirty times at standby temperatures and five times at normal operating temperatures. The diesel generator set was required to start and reach operating speed within ten seconds for this test and was step loaded to 50% of the continuous rating.

Each diesel generator set was subjected to one simulated loading sequence, using appropriate combinations of motor and resistive loads. Motors with horsepower ratings of 250, 750, and 1000 HP were used in combination to closely match the values for each sequence step load. Loading was continued until the 5400 KW generator load rating was reached. The generator set then underwent a loss of 100% load test with voltage and frequency monitored during the transient.

c. Margin Test

The diesel generator set underwent two margin tests, each consisting of start, acceleration, and step loading to a value at least 10% larger than the largest step load. A step loss of this load was then initiated, with voltage and frequency monitored during the transient.

d. Reliability Test

For the type of diesel generator set utilized for Prairie Island Unit 2, SACM applied extensive qualification testing for other nuclear sites. The results of this type testing included:

1. over 600 successful test cycles (start and load) without a failure,

2. over 1500 successful starts without a failure, and

3. over 100 starts with various subsequent loading profiles successfully applied.

This extensive testing, in conjunction with the factory testing described above, demonstrated the ability of the diesel generator sets to reliably start and carry load under required conditions. The high operational reliability of these generator sets and low failure rate (1.25 x 10 -3/hour) support the qualification of this design for emergency use at Prairie Island.

Site testing implemented the guidance of Reg Guide 1.108, August 1977, as outlined in NSP's letter of September 29, 1989 (Reference 5), including repeat of the factory 24-hour load run. The Unit 2 diesel generator preoperational testing program included tests that:

1. Demonstrated proper startup operation by simulating loss of all AC voltage and demonstrating that the diesel generator set could start automatically and attain the required voltage and frequency within acceptable limits.

2. Demonstrated proper operation under design accident loading sequence with voltage and frequency maintained within acceptable limits.

3. Demonstrated full load carrying capability for 24 hours of which 22 hours was at a load equivalent to the continuous (100% nameplate) rating of the diesel generator, and two hours was at a load equivalent to 110% of nameplate rating. This test, in conjunction with others, also verified proper operation of the cooling system.

4. Demonstrated proper operation during load shedding, including loss of the largest single load, and a complete loss of load, without exceeding voltage transient requirements and overspeed limits.

5. Demonstrated functional capability at full load temperature conditions by rerunning test one and two immediately following test three above.

6. Demonstrated the ability to synchronize with offsite power while connected to the emergency load, transfer this load to offsite power, isolate and return the diesel generator to standby status.

7. Demonstrated proper performance while switching from one fuel oil supply to another.

8. Demonstrated the capability to supply emergency power within required time was not impaired during periodic testing.

9. Demonstrated required reliability by performing 35 consecutive starts for each generator set.

10. Demonstrated proper functioning of the load sequencers under simulated emergency conditions to trip load breakers, start the diesel generators, select proper source for the emergency bus, and sequentially load the bus.

    A loss of power memory test was also performed on the programmable logic controller (PLC) to verify proper resumption of operation upon restoration of power to the PLC.

11. Verified air start cranking capacity to crank the diesel engine at least five times without recharging the air receiver.

The above tests and results are maintained in the Prairie Island plant files.

Periodic testing and surveillance of the diesel generators are performed in accordance with the requirements contained in the Technical Specifications. The tests specified for the diesel generators will demonstrate their operability and continued capability to start and to carry rated load. Each Emergency Diesel Generator is required to meet a target reliability of 97.5% as determined by NUMARC 87-00, Appendix D, Rev. 1. 04-022

8.9 ENVIRONMENTAL QUALIFICATION OF SAFETY-RELATED ELECTRICAL EQUIPMENT

The Equipment Qualification Branch of the Office of Nuclear Reactor Regulation, Nuclear Regulatory Commission (NRC), has required all licensees of operating reactors to submit a re-evaluation of the qualification of safety related electrical equipment which may be exposed to a harsh environment. This requirement was implemented primarily by the issuance, on January 14, 1980, of IE Bulletin No. 79-01B (Reference 8) with subsequent clarifying supplements in February, September, and October, 1980.

The Bulletin required that a master list of safety related systems and equipment be generated, all accident service conditions be defined, and the equipment be evaluated in accordance with guidelines in the bulletin.

Northern States Power Company has provided responses to the Bulletin in March, May, July and October 1980. The October 31, 1980 (Reference 9) submittal represented the final response to IE Bulletin No. 79-01B. This response included revised system component evaluation worksheets and provided a complete and current “Master List”.

On May 22, 1981, the NRC issued the Prairie Island Nuclear Generating Plant Safety Evaluation Report (SER) (Reference 10) which summarized their assessment of the March, May, July and October 1980 submittals. A response to IE Bulletin No. 79-01B SER was submitted to the NRC in a letter dated August 26, 1981 (Reference 11). This submittal includes a detailed response to the NRC evaluation and provides documentation of the Equipment Qualification Program that is being undertaken by Northern States Power Company. The program ensures that all safety related equipment is capable of performing its safety related function during postulated accident conditions.

A follow-up submittal was made to the NRC on April 30, 1982 (Reference 12). This submittal included a revised Master List and Component Evaluation sheets reflecting updated qualification information and newly identified components, qualification information for TMI Action Plan equipment and a list of outstanding items and schedule for completion. On August 27, 1982, information regarding pressure and temperature profiles outside containment in relation to the environmental qualification review was submitted in response to an NRC request (Reference 14).

On April 25, 1983, the NRC issued a Safety Evaluation for environmental qualification of safety-related electrical equipment which summarized their assessment of the August 26, 1981, February 1, April 21, and April 30, 1982 submittals (Reference 15). A response to this SER dated Nov. 23, 1983 summarized the status of deficiencies noted in the April 25, 1983 safety evaluation.

On January 21, 1983 the NRC published in the Federal Register the final rule on environmental qualification of electric equipment important to safety for nuclear power plants. The rule became effective on February 22, 1983. This rule superseded all previous NRC requirements for environmental qualification of electrical equipment.

This rule, Section 50.49 of 10 CFR 50, specifies the requirements for environmental qualification of electrical equipment important to safety located in a harsh environment. In accordance with this rule, equipment for Prairie Island may be qualified to the criteria specified in either the DOR guidelines or NUREG-0588, except for replacement equipment. Replacement equipment installed subsequent to February 22, 1983 must be qualified in accordance with the guidance of Regulatory Guide 1.89, unless there are sound reasons to the contrary.

A meeting was held with the NRC on December 1, 1983 to discuss all remaining open issues regarding environmental qualification, including acceptability of the environmental conditions for equipment qualification purposes. Discussions also included general methodology for compliance with 10 CFR 50.49, and justification for continued operation for those equipment items for which environmental qualification was not yet completed. The minutes of the meeting and proposed method of resolution for each of the environmental qualification deficiencies are documented in Reference 16.

The proposed resolutions for the equipment environmental qualification deficiencies, identified in earlier correspondence are described in Reference 15. During the December 1, 1983 meeting, the staff discussed the proposed resolution of each deficiency for each equipment item and found the NSP approach for resolving the identified environmental qualification deficiencies acceptable. The majority of deficiencies identified were documentation, similarity, aging, qualified life and replacement schedule. All open items identified in the SER dated April 25, 1983 (Reference 15) were also discussed and the resolution of these items were found acceptable by the NRC Staff.

The methodology used to determine compartment pressure and temperature profiles is described in USAR Appendix I.5.3 (Compartment Pressure and Temperature). Peak pressures and temperatures in principal compartments are identified, and referenced calculations provide peak values in other Auxiliary Building compartments as well as long-term pressure and temperature time histories.

Regulatory Guide 1.183, "Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors," provides guidance to licensees of operating power reactors on acceptable applications of ASTs; the scope, nature, and documentation of associated analyses and evaluations; consideration of impacts on analyzed risk; and content of submittals. This guide establishes an acceptable AST andidentifies the significant attributes of other ASTs that may be found acceptable by the NRC staff. This guide also identifies acceptable radiological analysis assumptions for use in conjunction with the accepted AST. This RG states that licensees may use either the AST or the TID-14844, "Calculation of Distance Factors for Power and Test Reactor Sites," assumptions for performing the required environmental qualification analyses to show that the equipment remains bounding. RG 1.183 further states that no plant modifications are required to address the impact of the difference in source term characteristics (i.e., AST versus TID-14844) on environmental qualification doses. 01406407

As part of implementing AST, Prairie Island will continue to use the TID 14844 methodology to determine radiation doses in the EQ analyses.

Three categories of electrical equipment were identified in 10 CFR 50.49 as requiring environmental qualification. Equipment described in paragraph (b)(1) of 10 CFR 50.49 has been identified through a review of the accident analyses provided in the FSAR, a review of the emergency procedures, a review of safety system flow diagrams and Q-List, and a review of the installed equipment locations with respect to postulated harsh environmental zones. Our current master equipment list includes all equipment within the scope of paragraph (b)(1) of 10 CFR 50.49.

Equipment identified in paragraph (b)(2) of 10 CFR 50.49 is non-safety-related electrical equipment whose failure could prevent accomplishment of safety functions of equipment identified in paragraph (b)(1) of 10 CFR 50.49.

This equipment was principally identified through system review criteria and identification of display instrumentation referenced in the LOCA and HELB emergency procedures. The methodology used is summarized below:

- The wiring diagrams of safety related electrical equipment as defined in paragraph (b)(1) of 10 CFR 50.49 were reviewed to identify any auxiliary devices, electrically connected directly into the control or power circuitry, whose failure due to postulated environmental conditions could prevent the required operation of the safety-related equipment.

- The review discussed above addressed the potential failure of safety-related electrical equipment after its qualified operating time but before the end of the postulated accident.

Post-accident monitoring equipment has been identified in accordance with paragraph (b)(3). In addition, our response to NUREG-0737, Supplement 1 - Generic Letter 82-33 was transmitted to the NRC on September 15, 1983. This letter identified the qualification requirements and implementation schedule for Regulatory Guide 1.97 equipment. This equipment was qualified and added to the master equipment list in accordance with the schedule provided in the September 15, 1983 letter.

The master equipment list contains the necessary equipment to mitigate the consequences of all Design Basis Accidents (DBAs) identified in the FSAR, including flooding in the auxiliary building.

Equipment qualification is an on-going process that requires implementation into the activities of plant operation. The master equipment list (EQML) will change over the course of plant life due to system design changes, replacement equipment, or additional (b)(1), (b)(2), and (b)(3) equipment identified through procedural changes, licensing changes, etc. The PINGP EQ Program was developed to establish and maintain the regulatory requirements for the environmental qualification of electrical equipment. The program provides for such activities as the identification of electrical equipment within the program, the environmental specifications by plant location, providing auditable documentation supporting the equipment's environmental qualification, and ensuring appropriate reviews affecting environmentally qualified equipment are performed as required.

Equipment in the D5/D6 Building, a "mild" environment, is not subject to the requirements of 10CFR50.49.

8.10 POWER OPERATED VALVES

8.10.1 Motor Operated Valves

IE Bulletin 85-03 “Motor-Operated Valve Common Mode Failures During Plant Transients due to Improper Switch Settings” and its supplement (Reference 22 and 23) were issued to ensure that switch settings on certain safety-related motor-operated valves (MOVs) were selected, set and maintained correctly to accommodate the maximum differential pressures expected during both normal and abnormal events within the design basis.

In June of 1989, IEB 85-03 was superseded by Generic Letter 89-10 “Safety-Related Motor Operated Valve Testing and Surveillance” (Reference 24). Generic Letter 89-10 recommended that a program be established to ensure that all safety-related MOVs are selected, set and maintained appropriately. Several supplements to Generic Letter 89-10 (Reference 25) have been issued to clarify program scope, schedule, and recommendations. In August 1995, the NRC conducted a closeout inspection to verify the completeness of NSP’s commitments made in response to Generic Letter 89-10 (Reference 26).

In September 1996, the NRC issued Generic Letter 96-05 “Periodic Verification of Design-Basis Capability of Safety related Motor-Operated Valves” (Reference 27) which superseded GL 89-10 and its supplements. The generic letter requested that licensees establish a program, or ensure the effectiveness of its current program, to verify on a periodic basis that safety related MOVs continue to be capable of performing their safety functions within the current licensing basis of the facility.

Prairie Island modified its periodic verification program to meet the intent of the generic letter. The NRC reviewed the Prairie Island periodic verification program and concluded that the program adequately addressed the actions requested in GL 96-05 (Reference 28).

8.10.2 Generic Letter 95-07, “Pressure Locking and Thermal Binding of Safety Related Power-Operated Valves”

Generic Letter 95-07 (Reference 29) was issued by the NRC requesting licensees to provide information concerning; (1) the evaluation of operational configurations of safety-related, power-operated gate valves for susceptibility to pressure locking and thermal binding; and (2) analyses, and needed corrective actions, to ensure that safety-related power-operated gate valves that are susceptible to pressure locking or thermal binding are capable of performing the required safety function.

All Motor Operated Valves (MOVs), Air Operated Valves (AOVs), and Hydraulically Operated Valves (HOVs) were reviewed to determine applicability of this issue.

For those valves which were identified to be potentially susceptible, an evaluation was performed to ensure each valve can perform its intended safety function. The NRC has determined that Prairie Island's evaluation and resulting corrective actions adequately addressed Generic Letter 95-07 (Reference 30).

A plant modification (Reference 40) drilled a 1/8" diameter hole in the upstream disc of the motor operated valve MV32206, and MV32207 (MV32208, MV32209) allows pressure inside the bonnets to equalize with upstream Residual Heat Removal cross-over line. The equalization in pressure will preclude pressure locking.

A Plant Modification (Reference 45) installed bonnet vents on MOVs MV32077 and MV32078. The bonnets of these valves have a vent line installed to eliminate the possibility of pressure in the bonnets. The valves are flex wedge gate valves. The vent will be routed back to the process piping. This equalization in pressure will preclude pressure locking. 01431472

8.11 REFERENCES

1. Letter, T.M. Parker (NSP) to Nuclear Regulatory Commission, “Reply to Questions on Design Report for the Station Blackout/Electrical Safeguards Upgrade Project”, July 10, 1991. (2850/1690)

2. Letter, C E Larson (NSP) to Director of Nuclear Reactor Regulation, “Interim Response to NRC Bulletin 88-10”, March 31, 1989. (2040/2135)

3. Letter, T M Parker (NSP) to Director of Nuclear Reactor Regulation, “Response to NRC Bulletin 88-10, Supplement 1, Nonconforming Molded-case Circuit Breakers”, November 6, 1989. (2040/2148)

4. Letter, D C DiIanni (NRC) to T M Parker (NSP), “Response to Bulletin 88-10 and Supplement 1 ’Nonconforming Molded-case Circuit Breakers’ Prairie Island Nuclear Generating Plant Unit Nos. 1 and 2”, March 7, 1990. (1857/0809)

5. Letter, T M Parker (NSP) to Director of Nuclear Reactor Regulation, “Project for Addition of Two Emergency Diesel Generators”, September 29, 1989.

6. Deleted

7. Letter, D C DiIanni (NRC) to T M Parker (NSP), “Safety Evaluation Related to the Emergency Diesel Generator Qualification Plan (TAC Nos 68588 and 68589)”, January 31, 1990. (30814/0111)

8. IEB 79-01B, Environmental Qualification of Class IE Equipment, January 14, 1980. (1061/0451)

9. Letter, D E Gilberts, (NSP) to J G Keppler (NRC), “Prairie Island Nuclear Generating Plant - Final Response to IE Bulletin No. 79-01B”, October 31, 1980. (1061/0996)

10. Letter, R A Clark to L O Mayer, “Environmental Qualification of Safety-Related Equipment” (includes SER), May 22, 1981. (18309/1155)

11. Letter, L O Mayer (NSP) to Director of Nuclear Reactor Regulation, “Response to IE Bulletin No. 79-01B Safety Evaluation Report”, August 26, 1981. (18309/1900)

12. Letter, L O Mayer (NSP) to Director of Nuclear Reactor Regulation, “Response to IE Bulletin 79-01B Safety Evaluation Report”, April 30, 1982. (18311/1871)

13. Licensee Event Report, RE-93-14, "Cable Separation at Main Control Board", December 16, 1993. (2869/0157)

14. Letter, D Musolf (NSP) to Director of Nuclear Reactor Regulation, "Pressure and Temperature Profiles Outside Containment", August 27, 1982. (18312/1023)

15. Letter, R A Clark to D M Musolf, "Safety Evaluation for Environmental Qualification of Safety-Related Electrical Equipment, April 25, 1983. (18347/2178)

16. Letter, D M Musolf (NSP) to Director of Nuclear Reactor Regulation, "Resolution of Safety Evaluation Report for Environmental Qualification of Safety-Related Electrical Equipment", January 16, 1984. (19896/0388)

17. WCAP-10961-P, "Steamline Break Mass/Energy, Releases for Equipment Environmental Qualification Outside Containments" Report to the Westinghouse Owners Group, October, 1985.

18. Deleted

19. ENG-EE-171, Degraded Voltage Analysis.

20. Letter, NSP to NRC, "Response to NRC Generic Letter 91-06: Resolution of Generic Letter Issue A-30," "Adequacy of Safety Related DC Power Supplies," 10-28-91.

21. Calculations 91-02-11, 91-02-12, 91-02-21 and 91-02-22, Battery Sizing and System Voltage Drop and Short Circuit Analyses for Safeguard Batteries 11, 12, 21 and 22 respectively.

22. IE Bulletin 85-03, "Motor-Operated Valve Common Mode Failures During Plant Transients due to Improper Switch Settings", dated November 15, 1985.

23. IE Bulletin 85-03, Supplement 1, "Motor-Operated Valve Common Mode Failures During Plant Transients due to Improper Switch Settings", dated April 27, 1988.

24. Generic Letter 89-10, "Safety-Related Motor Operated Valve Testing and Surveillance" dated June 28, 1989.

25. Generic Letter 89-10, "Safety-Related Motor Operated Valve Testing and Surveillance" - Supplements 1 through 7, various dates.

26. NRC correspondence dated August 17, 1995, "Close-out Inspection of Generic Letter 89-10 (NRC Inspection Report No. 50-282/95010(DRS); 50-306/95010(DRS)"

27. Generic Letter 96-05 “Periodic Verification of Design-Basis Capability of Safety related Motor-Operated Valves” dated September 18, 1996.

28. NRC correspondence dated December 29, 1999, “Prairie Island Nuclear Generating Plant, Units 1 and 2 – Closure of Generic Letter 96-05, “Periodic Verification of Design Basis Capability of Safety-Related Motor-Operated Valves” (TAC Nos. M97089 and M97090)

29. Generic Letter 95-07, “Pressure Locking and Thermal Binding of Safety Related Power-Operated Valves” dated August 17, 1995.

30. NRC correspondence dated August 24, 1999, “Prairie Island Nuclear Generating Plant, Units 1 and 2 – Closure of Generic Letter 95-07, “Pressure Locking and Thermal Binding of Safety Related Power-Operated Valves” Prairie Island Nuclear Generating Plant (TAC Nos. M93507 and M93508)

31. Not Used

32. Letter, D. C. Dilanni (NRC) to T.M. Parker (NSP), “Safety Evaluation of the Prairie Island Nuclear Generating Plant Unit Nos. 1 and 2; Station Blackout Rule 10 CFR 50.63 (TAC Nos. 68588 and 68589)”, September 18, 1990 (30814/3052)

33. Letter, D. Musolf (NSP) to Director of Nuclear Reactor Regulation (NRC), “Loss of All Alternating Current Power Information Required by 10 CFR Part 50, Section 50.63(c)(1)”, April 13, 1989

34. Letter ESU-3456, “Fulfill of SBO Rule (10CFR50.63); Verification of Supplying AAC Power to SBO Unit within 10 Minutes”, March 11, 1994 (2759/86)

35. 10CFR50.59 Screening 1828, Rev. 0 (4128/0559)

36. Calculation ENG-EE-045, “Diesel Generator Steady State Loading for a LOOP Coincident with an SBO”

37. Calculation ENG-ME-443, “Condensate Storage Tank Sizing”

38. Engineering Change Evaluation, EC #20717, Rev. 1, Station Position on D5 and D6 Emergency Diesel Generator Operability with Regards to the Number of Starting Air Receivers – Answers Aug. 2012 P.I. & R. (NRC Problem Identification and Resolution Inspection) Question #100

39. Engineering Change Evaluation, EC #20927, Rev. 0, D5/D6 EDG, “Availability” with Regards to the Number of Charged Starting Air Receivers

40. PINGP Modification EC19490, “(PRI 75) Drill RHR to SI Suction Valve Discs to Eliminate Pressure Locking Affected Valves are MV-32206 and MV-32207 in Unit 1 and MV-32208 and MV-32209 in Unit 2.”

41. Calculation ENG-EE-018, “Unit 2 Diesel Generator Sequence Loading for an SI Event (LOCA) Concurrent with a LOOP”.

42. Calculation ENG-EE-021, “Diesel Generator Steady State Loading for an SI Event Concurrent with Loss of Offsite Power (LOOP) for D1, D2, D5, D6”.

43. Calculation ENG-EE-183, “Unit 1 Electrical Transient Analysis for a LOCA Concurrent with a LOOP”.

44. Calculation 32-9218303, Rev. 1, Prairie Island Nuclear Generating Plant Unit 2 Diesel Engine Air Start Calculation. 01423445

45. Modification EC 23491, “Vent RHR Sump B Suction Valve Bonnets to Eliminate Pressure Locking.” 01431472

TABLE 8.4-1, DELETED

TABLE 8.4-2, DELETED

TABLE 8.4-3, DELETED

TABLE 8.4-4, DELETED

TABLE 8.5-1, DELETED

TABLE 8.5-2, DELETED 01407637

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FIGURE 8.2-1,
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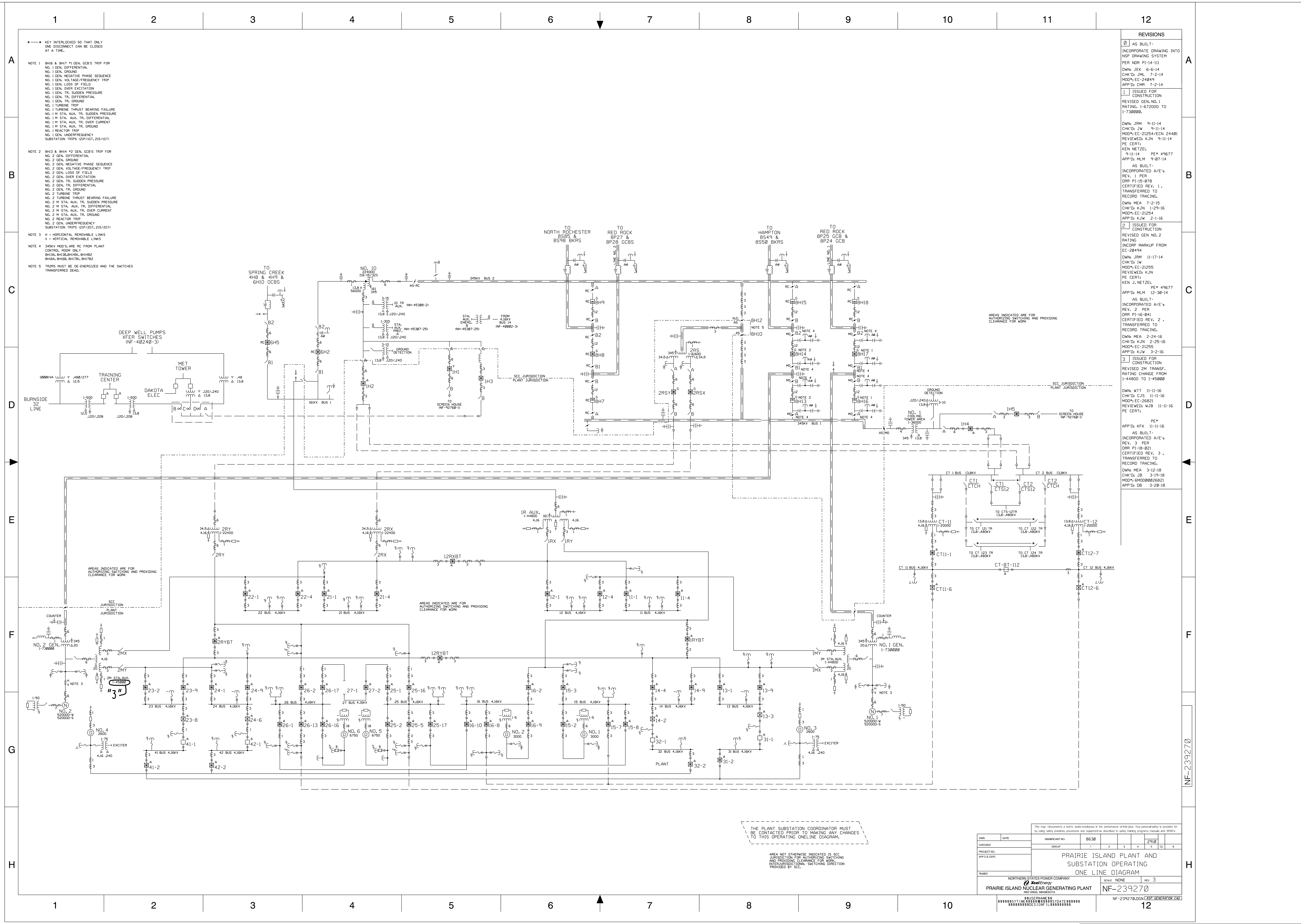

FIGURE 8.2-2 REV. 35

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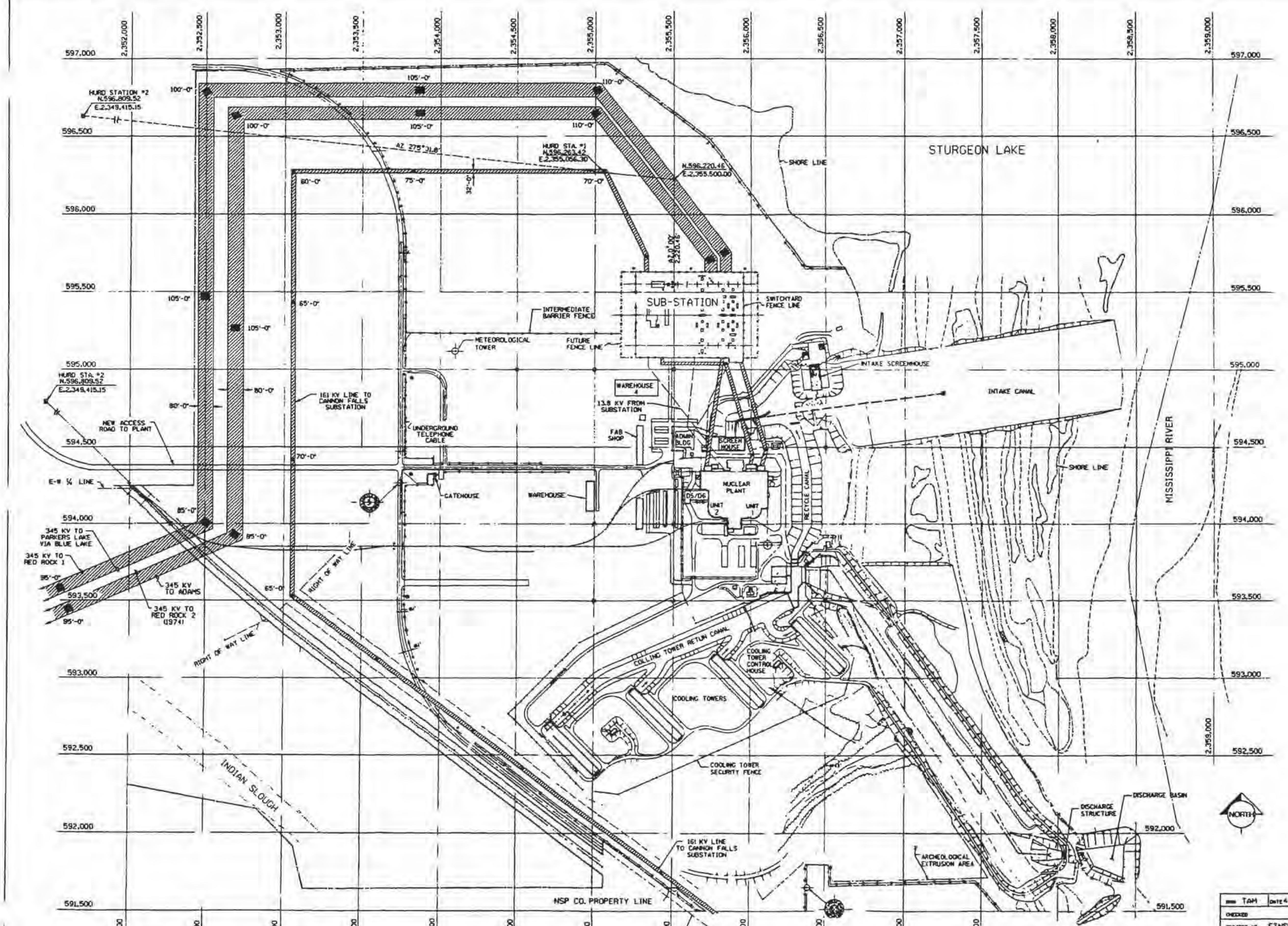
REVISIONS



NOTES:

REF LIST OF DWGS - NF-38204-8
YARD PLAN DWGS - NF-38204-1 THRU -10
SITE PLAN - NF-116972

LEGEND	
NAME OF SYSTEM	SYMBOL
N.S.P. Co. PROPERTY LINE	
SHORE LINE	
ROAD	
RAILROAD TRACK	
SECURITY FENCE	
SUB-STA. FENCE	
EXCLUSION FENCE	
UNDERGROUND CABLE	
70'-0" NUMBER (70'-0") INDICATES HEIGHT TO LOWEST TOWER ARM	

DRN TAM DATE 4-30-98
CHECKED
PROJECT NO. ETNSUR
APPD & CERT.
CAD FILE U08203.DGN U08203.CIT

SITE ARRANGEMENT OF TRANSMISSION LINES AND UNDERGROUND CABLES

NORTHERN STATES POWER COMPANY
PRAIRIE ISLAND NUCLEAR GENERATING PLANT
RED WING MINNESOTA

SCALE NONE

FIGURE 8.2-3 REV. 18

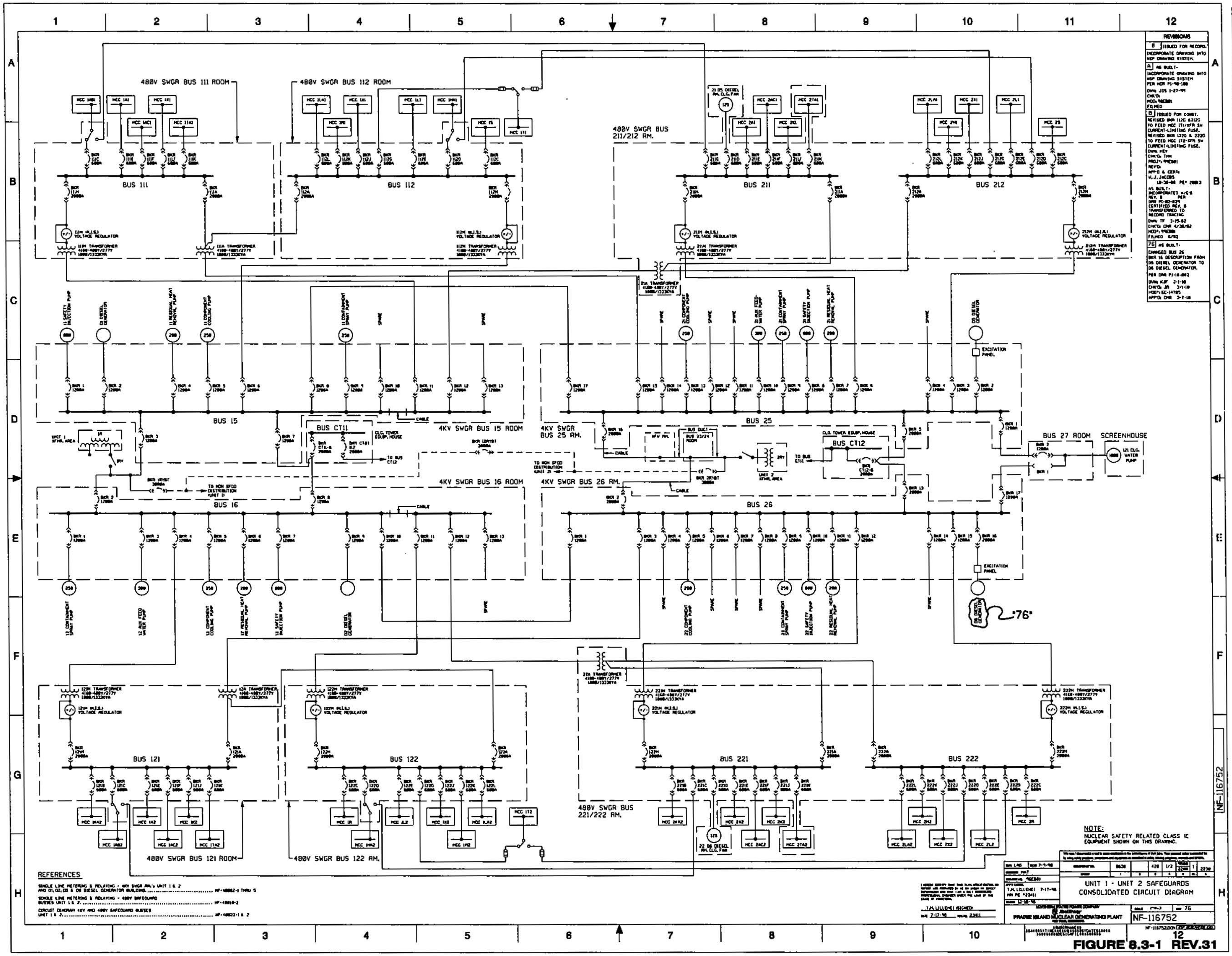


FIGURE 8.3-1 REV.31

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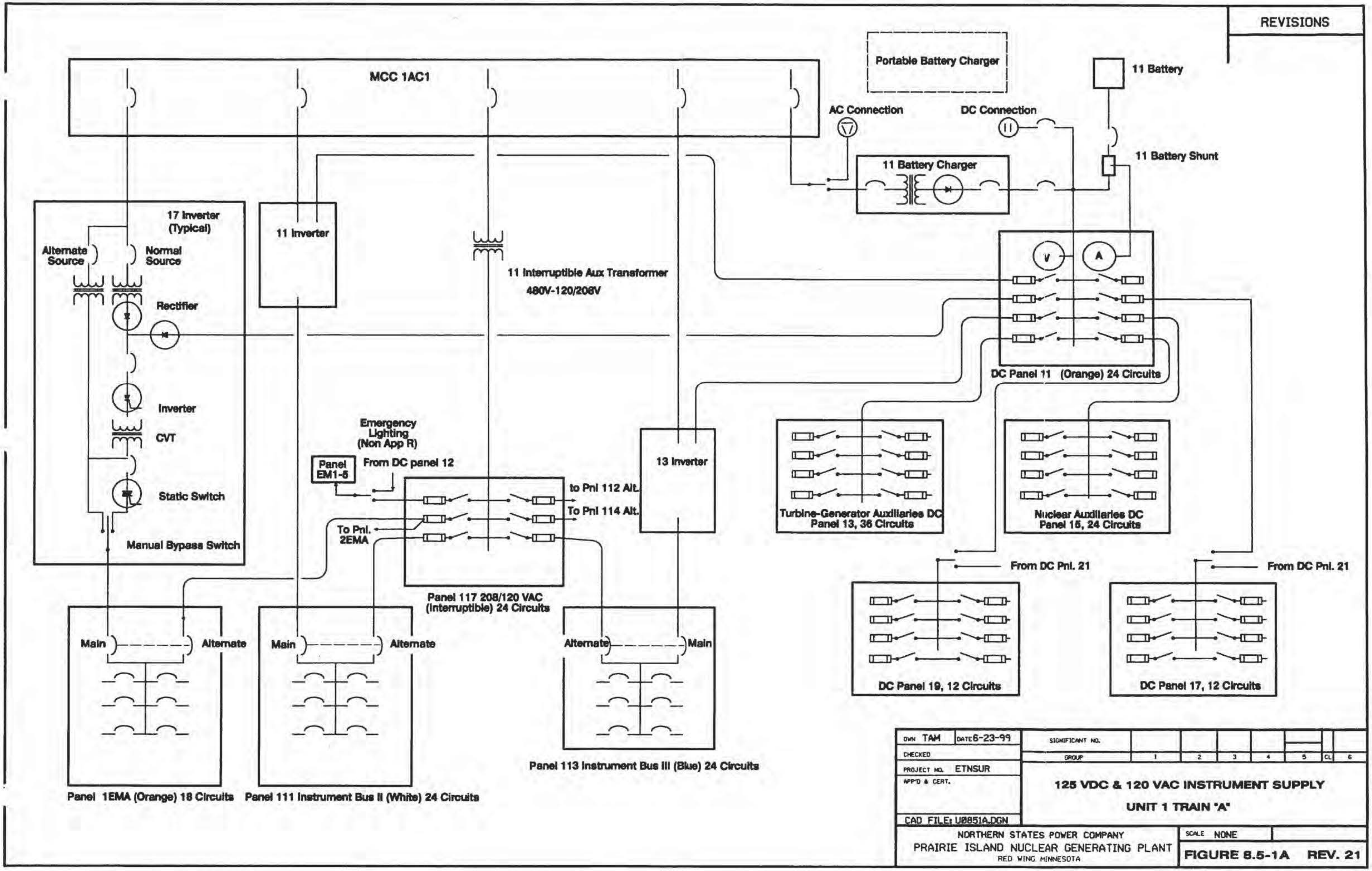
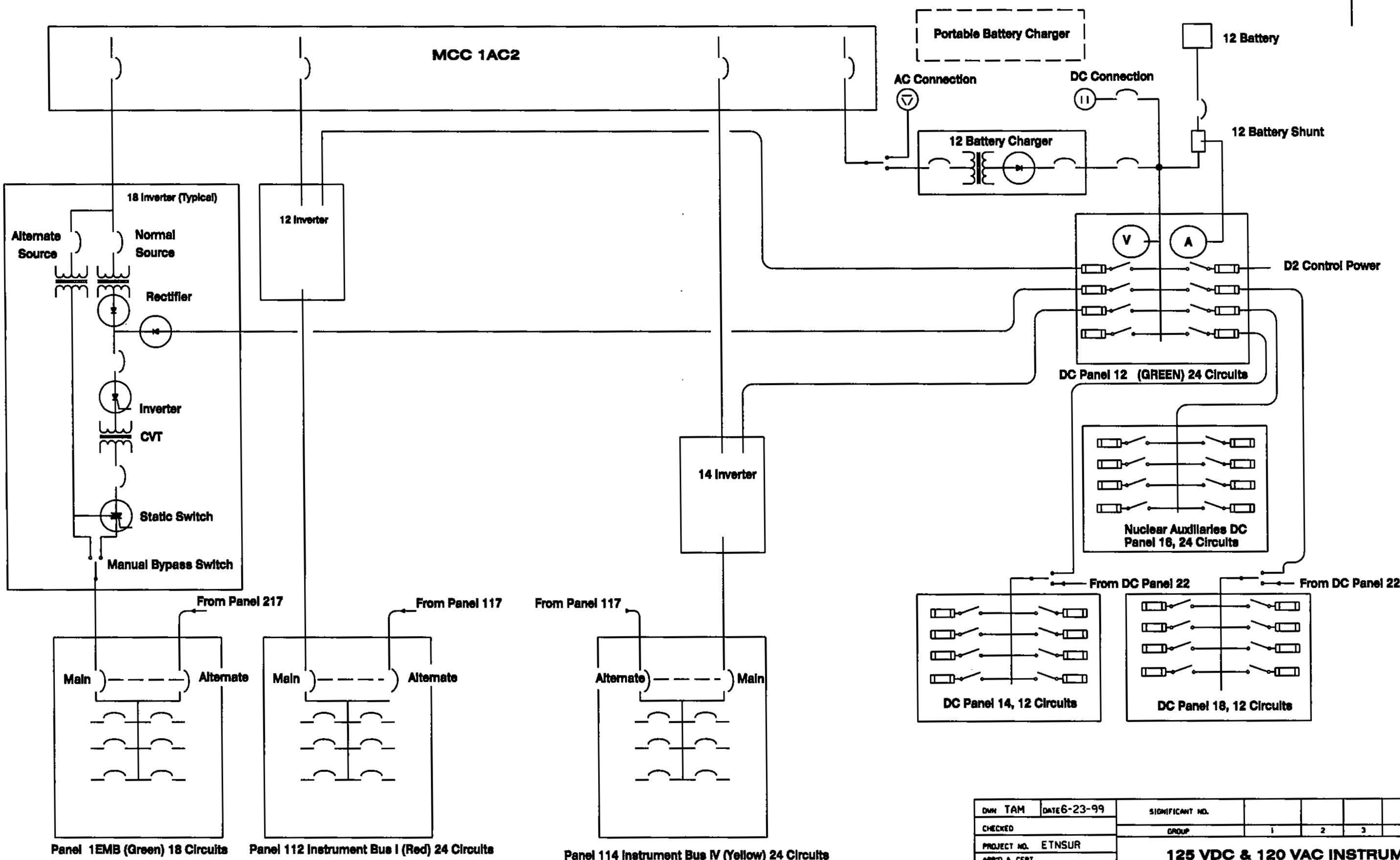

REVISIONS
MCC 1AC1
Portable Battery Charger
11 Battery
AC Connection
DC Connection
11 Battery Shunt
11 Battery Charger
17 Inverter
(Typical)
Alternate Source
Normal Source
Rectifier
Inverter
CVT
Static Switch
Manual Bypass Switch
11 Inverter
11 Interruptible Aux Transformer
480V-120/208V
V
A
DC Panel 11 (Orange) 24 Circuits
Emergency Lighting (Non App R)
Panel EM1-5
From DC panel 12
to Pnl 112 Alt.
To Pnl 114 Alt.
To Pnl. 2EMA
13 Inverter
Panel 117 208/120 VAC (Interruptible) 24 Circuits
Turbine-Generator Auxiliaries DC Panel 13, 36 Circuits
Nuclear Auxiliaries DC Panel 15, 24 Circuits
From DC Pnl. 21
From DC Pnl. 21
DC Panel 19, 12 Circuits
DC Panel 17, 12 Circuits
Main
Alternate
Main
Alternate
Alternate
Main
Panel 1EMA (Orange) 18 Circuits
Panel 111 Instrument Bus II (White) 24 Circuits
Panel 113 Instrument Bus III (Blue) 24 Circuits
DWN TAM
DATE 6-23-99
CHECKED
PROJECT NO. ETNSUR
APP'D & CERT.
CAD FILE: U0851A.DGN
SIGNIFICANT NO.
GROUP
1
2
3
4
5
CL
6
125 VDC & 120 VAC INSTRUMENT SUPPLY
UNIT 1 TRAIN "A"
NORTHERN STATES POWER COMPANY
PRAIRIE ISLAND NUCLEAR GENERATING PLANT
RED WING MINNESOTA
SCALE NONE
FIGURE 8.5-1A REV. 21

REVISIONS



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DWN TAM	DATE 6-23-99	SIGNIFICANT NO.	
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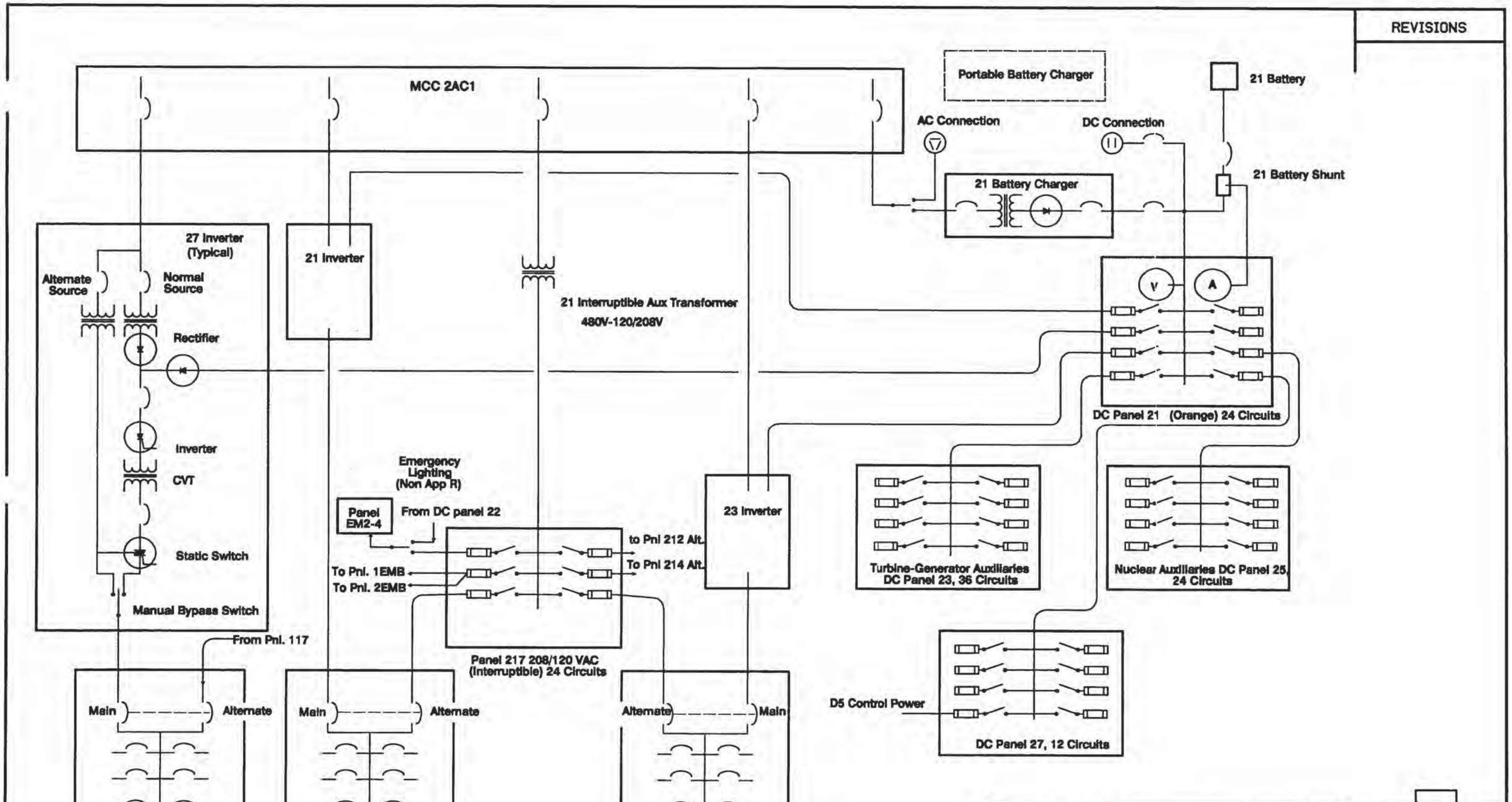
PROJECT NO. ETNSUR		125 VDC & 120 VAC INSTRUMENT SUPPLY	
APP'D & CERT.		UNIT 1 TRAIN "B"	
CAD FILE: U0851B.DGN			

NORTHERN STATES POWER COMPANY
PRAIRIE ISLAND NUCLEAR GENERATING PLANT
RED WING MINNESOTA

SCALE NONE

FIGURE 8.5-1B REV. 31



DWN TAM	DATE 6-23-99	SIGNIFICANT NO.	
CHECKED		GROUP	1 2 3 4 5 CL 6
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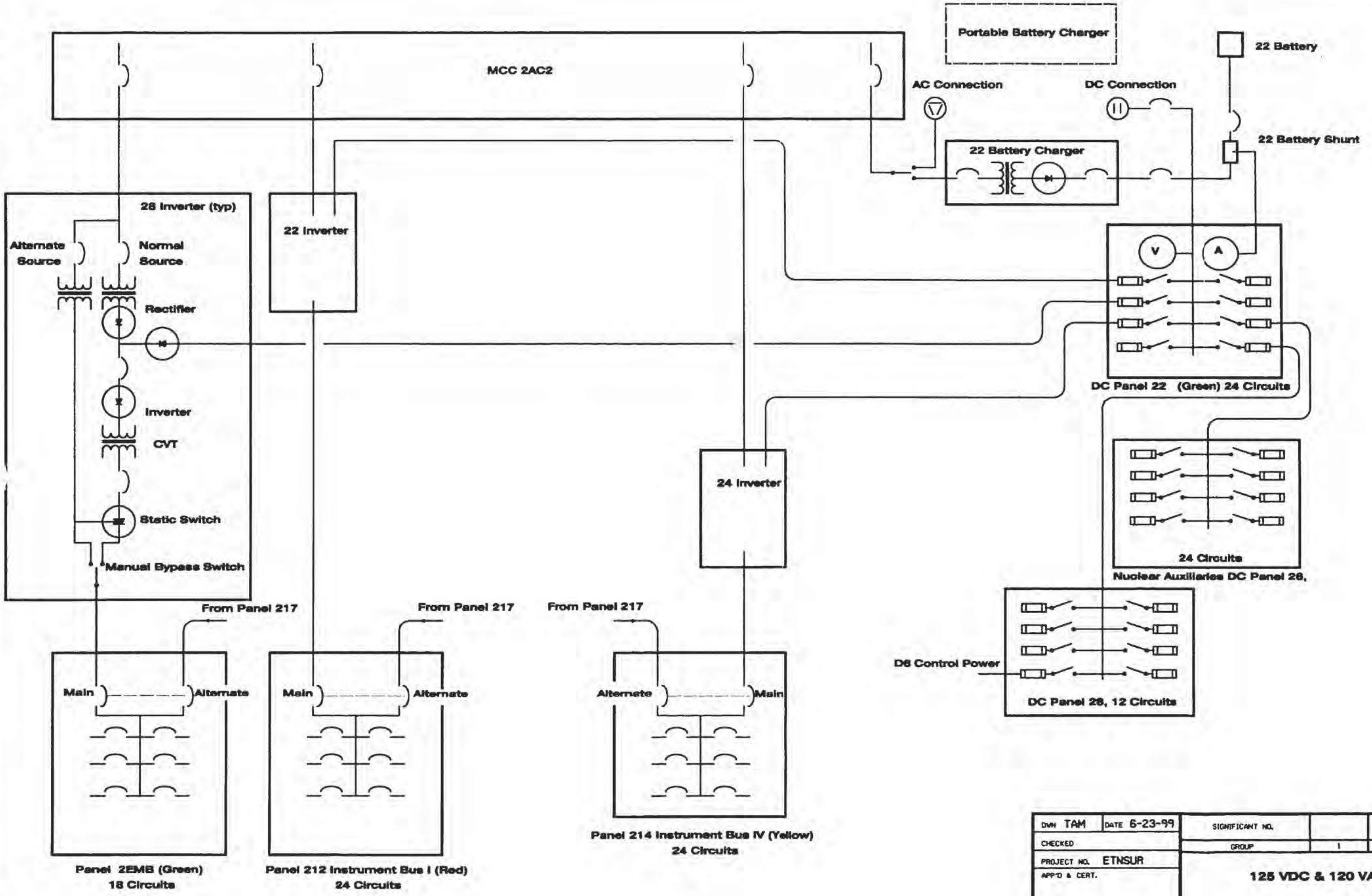
APP'D & CERT.		**UNIT 2 TRAIN 'A'**	
CAD FILE: U0852A.DGN			
NORTHERN STATES POWER COMPANY PRAIRIE ISLAND NUCLEAR GENERATING PLANT RED WING MINNESOTA		SCALE NONE	
		FIGURE 8.5-2A	**REV. 21**



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PROJECT NO. ETNSUR									
APP'D & CERT.									
CAD FILE: U08528.DGN									

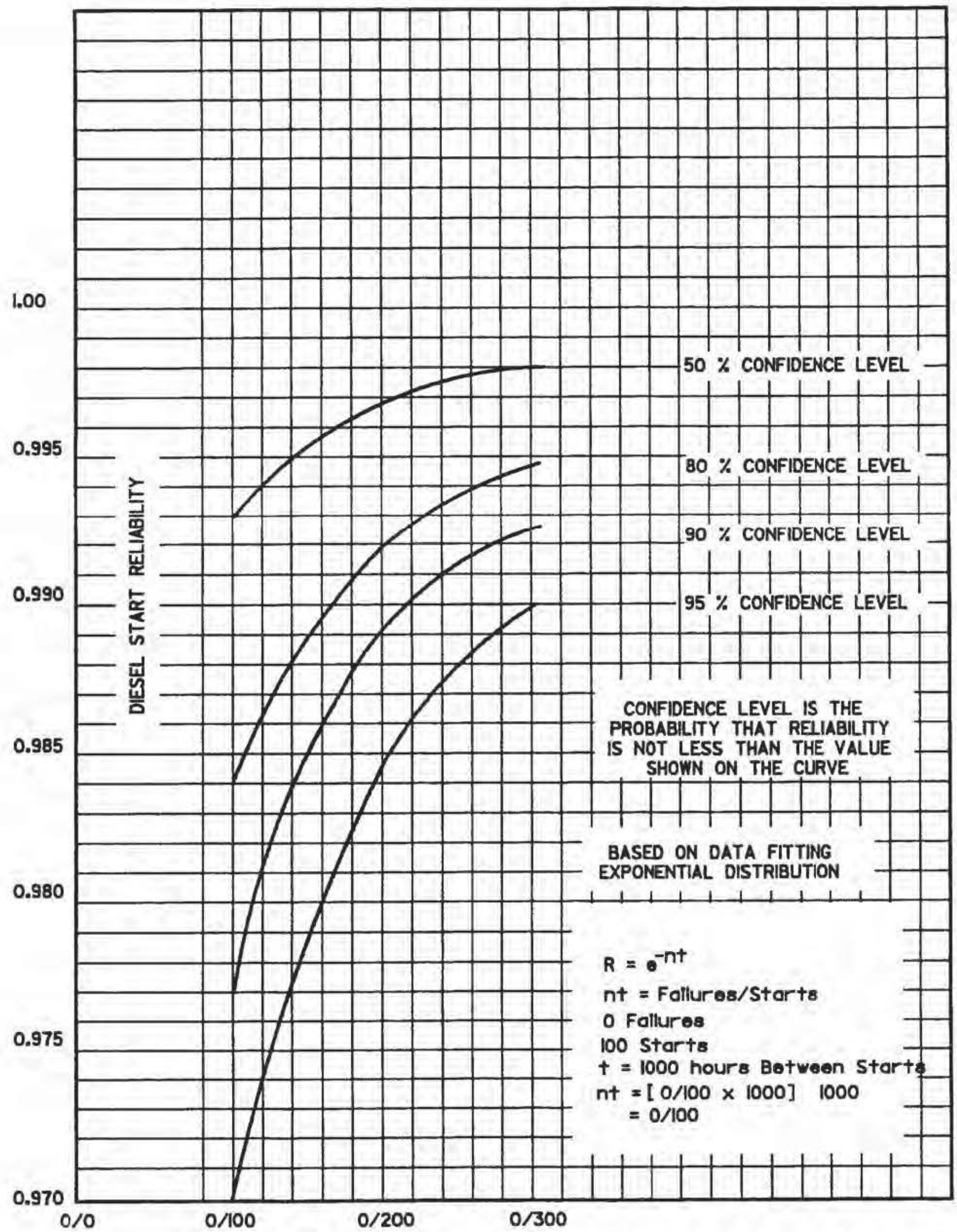
125 VDC & 120 VAC INSTRUMENT SUPPLY

UNIT 2 TRAIN "B"

NORTHERN STATES POWER COMPANY
PRAIRIE ISLAND NUCLEAR GENERATING PLANT
RED WING MINNESOTA

SCALE NONE

FIGURE 8.5-2B REV. 21



DIESEL RELIABILITY
STARTS / STOPS

DWN TAM	DATE 6-23-99	NORTHERN STATES POWER COMPANY PRAIRIE ISLAND NUCLEAR GENERATING PLANT RED WING MINNESOTA	SCALE: NONE
CHECKED	CAD FILE U08801.DGN		FIGURE 8.8-1 REV. 18