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10 CFR 50.90

ATTN: Document Control Desk
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555-0001

Browns Ferry Nuclear Plant, Units 1, 2, and 3
Facility Operation License Nos. DPR-33, DPR-52, and DPR-68
NRC Docket Nos. 50-259, 50-260, and 50-296

Subject: **Revised Technical Specifications Change TS-468 - Request to Extend Completion Time for TS 3.8.1 Required Action B.4 - Emergency Diesel Generators A, B, C, D, 3A, 3B, 3C, and 3D**

References:

1. TVA Letter to NRC, Browns Ferry Nuclear Plant, Units 1, 2, and 3, "Technical Specifications Change TS-468 - Request to Extend Completion Time for TS 3.8.1 Required Action B.4 - Emergency Diesel Generators A, B, C, D, 3A, 3B, 3C and 3D," dated February 18, 2010
2. NRC Letter to NRC, "Browns Ferry Nuclear Plant, Units 1, 2 and 3 - Request for Additional Information Regarding Extending Completion Times for Emergency Diesel Generators (TAC Nos. ME3423, ME3424, and ME3425)," dated May 7, 2010
3. TVA Letter to NRC, Browns Ferry Nuclear Plant, Units 1, 2, and 3, "Technical Specification Change - TS-468 - Responses to Request for Additional Information Regarding Extending Completion Times for Emergency Diesel Generators (TAC Nos. ME3423, ME3424, and ME3425)," dated May 28, 2010
4. NRC Letter to TVA, Browns Ferry Nuclear Plant, Unit 1, "Summary of June 29, 2010, Meeting Regarding Extension of Allowed Outage Time for Emergency Diesel Generators (TAC Nos. ME3423, ME3424, and ME3425)," dated November 10, 2010

On February 18, 2010 (Reference 1), the Tennessee Valley Authority (TVA) submitted a request for amendment to the Technical Specifications (TS) for Browns Ferry Nuclear Plant (BFN), Units 1, 2, and 3. The amendment proposed to extend the completion time of TS 3.8.1 Required Action B.4 (one diesel generator (DG) inoperable) from 7 to 14 days.

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NRR

This revised License Amendment Request (LAR) supersedes entirely the Reference 1 LAR, and replaces the risk-based justification with a deterministic engineering justification including availability of temporary DGs during the proposed extended completion times.

TVA based the revised LAR on NRC staff guidance provided in a public meeting with TVA on June 29, 2010 (Reference 4), and on the approved license amendments for the plants listed in Section 4.2, Precedent, of this application.

Enclosure 1 to this letter provides the justification for this request. Enclosure 2 provides marked-up pages of the affected TS and Bases pages. Enclosure 3 provides retyped pages of the affected TS and Bases pages. Enclosure 4 provides a list of new commitments.

TVA has determined that there are no significant hazards considerations associated with the proposed TS changes and that the proposed TS changes qualify for a categorical exclusion from environmental review pursuant to the provisions of 10 CFR 51.22(c)(9). Additionally, in accordance with 10 CFR 50.91(b)(1), TVA is sending a copy of this letter and enclosures to the Alabama State Department of Public Health.

This LAR includes new regulatory commitments consistent with those provided by the licensees for the precedent amendments. Please direct any questions concerning this matter to Tom Matthews at (423) 751-2687.

I declare under penalty of perjury that the foregoing is true and correct.
Executed on the 12th day of November, 2010.

Respectfully,

R. M. Krich

Enclosures:

1. Evaluation of Proposed Change
2. Proposed TS and TS Bases Changes (mark-ups)
3. Proposed TS and TS Bases Changes (clean)
4. Commitment List

cc (Enclosures):

NRC Regional Administrator – Region II
NRC Senior Resident Inspector – Browns Ferry Nuclear Plant
State Health Officer - Alabama State Department of Public Health

**ENCLOSURE 1**

**Browns Ferry Nuclear Plant**
**Units 1, 2, and 3**
**Technical Specifications (TS) Change 468**

**License Amendment Request to Extend Completion Times for TS 3.8.1 Required Action A.3, B.2, and B.5.**

**EVALUATION OF PROPOSED CHANGE**

## 1.0 DESCRIPTION

Pursuant to 10 CFR 50.90, the Tennessee Valley Authority (TVA) is submitting a request for changes to Technical Specification (TS) 3.8.1 of License DPR-33 for Browns Ferry Nuclear Plant (BFN) Unit 1, License DPR-52 for BFN Unit 2, and License DPR-68 for BFN Unit 3. The proposed TS changes include:

a) Extend the Completion Time (CT) for Required Action B.5 (return of an inoperable diesel generator (DG) to operable status) from 7 days to 14 days, based on availability of 2 non-safety related temporary diesel generators (TDGs);
b) Make commensurate changes to the maximum CTs for Required Action A.3 and B.4 by extending these times from 14 days to 21 days; and
c) Eliminate a historical footnote regarding a one-time extension to the first CT of BFN Unit 3 Required Action B.4.

These changes will provide operational and maintenance flexibility. They will allow performance of more DG inspection and maintenance activities during plant operation, reducing plant refueling outage duration and improving DG availability during shutdown plant conditions. They will also allow more time for unanticipated DG repairs.

This License Amendment Request (LAR) includes only deterministic engineering justification, and supersedes the previous similar LAR, dated February 18, 2010, that included risk-based justification.

This LAR is based on NRC staff guidance provided in a public meeting with TVA on June 29, 2010, and on the approved license amendments for the plants listed in Section 4.2, Precedent, of this application. This request includes regulatory commitments consistent with those provided by the licensees for the precedent amendments.

## 2.0 PROPOSED CHANGE

### 2.1 Need for Proposed Changes

Currently, BFN Units 1, 2, and 3 TS 3.8.1, Required Action B.4 permits a DG to be inoperable for a period of seven days, before the DG is returned to operable status. Based on plant-specific experience, the 7-day duration does not permit adequate time to perform some planned and potential corrective DG maintenance. A longer DG allowed outage time will reduce the regulatory burden associated with planned or emergent DG maintenance activities, and minimize the need for expedited licensing actions.

The DG manufacturer and the owners group are recommending additional preventive maintenance activities to be performed during the 12-year or other long term maintenance intervals that may require multiple entries into the LCO (i.e., TS Actions) and multiple DG starts if all of the planned activities cannot be completed within the existing 7-day CT. The extended CTs are requested to permit performing DG manufacturer and owners group recommended replacement activities using fewer TS Action entries than can be accomplished within the current 7-day CT. If these activities (listed below) can be combined and performed over an extended CT, the number of entries into the TS Actions and the number of associated DG starts performed for post-maintenance testing prior to exiting the TS Actions will be reduced.

Planned replacement activities over the next 5 years include the following:

1. Lube oil modification (estimated at 178 hours)
2. Governor modification (estimated at 124 hours)
3. Starting air modification (estimated at 124 hours)
4. Battery replacement (estimated at 48 hours)
5. Heat exchanger modification (estimated at 144 hours)
6. Generator vibration/alignment (estimated at 96 hours)
7. Stub shaft upgrade (estimated at 120 hours)

These component upgrades are important to maintaining the reliability and availability of this system.

In addition, TVA is also considering other long term improvements such as:

1. Replacing the governor booster pumps with pneumatic boosters
2. Upgrading the air start flow control system to eliminate the 3 way pilot valves
3. Upgrading the 7 day fuel tank level indication/annunciation
4. Modifying the DGs to provide a larger more corrosion resistant heat exchangers
5. Installing generator heaters
6. Upgrading diesel controls for more auto trips when in test/maintenance mode
7. Upgrading the DG instrumentation system to be consistent with that provided for WBN and SQN (i.e., cylinder exhaust temperature monitoring system, etc.)

**2.2 Proposed Changes**

A description of the proposed TS changes is provided below. The specific changes to the BFN TS and TS Bases for Units 1, 2, and 3 are indicated in the markups provided in Enclosure 2. The retyped (clean) pages of the BFN TS and TS Bases for Units 1, 2, and 3 are provided in Enclosure 3.

TS 3.8.1 - new Required Action B.2 and associated completion times

The new required action proposed is to evaluate the availability of both temporary diesel generators. The proposed completion times are 1 hour and once per 12 hours thereafter. Subsequent current TS 3.8.1 B required actions are renumbered.

TS 3.8.1 – CT – Required Action B.4

Current Required Action B.4 is proposed to be renumbered as B.5 and extended from 7 days to 14 days only when TDGs are available.

In addition, TVA is proposing to eliminate a reference to a historical footnote from the CT of TS 3.8.1, Required Action B.4 for BFN Unit 3. This footnote refers to a one-time extension that has expired. The elimination of this footnote is an administrative change with no impact on safety, because the provisions reflected in the footnote have expired.

TS 3.8.1 - Maximum CT – Required Actions A.3 and B.4

The maximum CT for current Required Actions A.3 and B.4 is proposed to be extended from 14 days to 21 days. The maximum CT limits the total time that Limiting Condition for Operation (LCO) 3.8.1 is not met while concurrently or simultaneously in Conditions A and B. This CT is the sum of the CT for Required Action A.3 and the CT for Required Action B.4. TVA is proposing to increase the CT for Required Action B.4 to 14 days (described above); thus, the sum of the first CTs for Required Action A.3 and B.4 will be increased from 14 days to 21 days. This is explained in the TS Bases markups included for information.

**2.3 Bases for Proposed Changes**

The CT of Required Action B.4 of TS 3.8.1 currently allows only 7 days to perform maintenance, testing, or troubleshooting and repair of a DG, and return it to an operable status when BFN Unit 1, 2, or 3 is in Modes 1-5. Recent experience at TVA has shown that the current 7-day CT is insufficient to support extensive trouble shooting, maintenance, and post-maintenance testing; examples include the 12 year preventative maintenance (PM) activities and Lube Oil System Modification, while a unit is at power.

The BFN DGs are subject to a vendor recommended PM program, which involves several periodic service and inspection activities, including a major PM outage every 12 years. The BFN DGs were manufactured by General Motors Electromotive Division (EMD) and the PM program is based on EMD recommendations.

The 12-year PM requires an extensive diesel engine disassembly, including removal of pistons, cylinder liners, and connecting rods. During the last BFN 12-year PM, the longest out of service time for a diesel was 180.4 hours. The unplanned availability for all eight diesel generators averages 4.5 days based on available data from 1994 to 2007.

TVA's experience with the 12-year PM activities is limited by the infrequency of performance. However, the predicted schedule duration has considerably more uncertainty than routinely conducted activities and could encounter unexpected delays, thus raising the potential for exceeding the 7-day CT. The extension of the 7-day DG CT to 14 days gives extra time for completing the PM activities, and thus reduces the potential of a TS forced reactor shutdown and minimizes the need for expedited licensing actions seeking approval of more completion time. TVA could partition the 12-year DG mechanical PM and electrical PM into two maintenance activities. However, this is not desirable from an overall DG availability perspective since this approach removes the DGs from service for a longer period of time than if performed as a combined activity. This is because setup, restoration, and post-maintenance testing associated with the maintenance are often duplicative, and must be repeated each time the DGs undergo maintenance. TVA has estimated the proposed combined outage approach can save 58 hours of outage time per DG. For the eight DGs, this is equivalent to a total of 464 hours (19.3 days), which represents a significant increase in overall DG availability.

TVA has considered scheduling the 12-year PM activities during refueling outages. However, Units 1 and 2 share four DGs, and TVA does not intend to schedule simultaneous outages for these units. No more than two of the four DGs could be serviced within a single refueling outage without extending the outage, since only one DG is removed from service at a time in order to minimize shutdown risk. There are also manpower constraints. Maintenance on DGs is performed by a limited number of experienced craftsmen due to the specialized nature of the maintenance. This manpower limitation likewise restricts working on more than one DG at a time. Additionally, previous work experience indicates that shorter DG outages can be achieved by performing preventive maintenance while operating since work resources are focused on a single objective. This focus results in better planning of work, dedicated manpower allocation, and greater resource availability for contingency work. For these reasons, it is desirable to be able to perform DG maintenance during power operations.

Having a 14-day CT is also desirable as a contingency provision for major unexpected DG failures where time needed for repairs would exceed 7 days. This will reduce the risk of a TS forced reactor shutdown and minimize the need for expedited licensing actions seeking approval of more completion time.

As a condition for implementing an extended 14-day CT for a single inoperable emergency DG, an independent alternating power source consisting of two TDGs with paralleled output will be provided to supply power to any of the eight Engineered Safeguards Features (ESF) buses via the 4.16kV Tie Bus. By procedure and TS Bases, the TDGs will be supplying power only to one ESF bus at a time, and only during a station blackout (SBO) event. The combined capacity of both TDGs will exceed that of each permanent DG.

The TDGs will be commercial-grade and not designed to meet Class IE or safety-related system requirements. Mechanical and electrical reliability of the TDGs will be demonstrated by initial acceptance testing and inspections. The role of the TDGs is mitigation of an SBO event, as a defense-in-depth source of AC power to one ESF board.

Both TDGs will be verified available prior to removing a DG from service for maintenance that is expected to exceed the normal 7-day CT. If one or both TDGs are or become unavailable during the extended CT of the inoperable DG, then action will be required to restore both TDGs to available status or to restore the DG to operable status within 7 days from discovery of an unavailable TDG. However, if the TDG unavailability occurs sometime after 4 days of continuous DG inoperability, then the remaining time to restore both TDGs to available status or to restore the DG to operable status will be limited to 72 hours (i.e., 3 days).

The amendment proposed herein provides (1) more efficient use of resources, and (2) a reduction in unnecessary burden, as detailed below.

1. Efficient Use of Resources
   The extended CT, to permit a DG to be removed from service for 14 days to perform recommended maintenance or to trouble shoot and repair an inoperable DG while the unit is in Mode 1-5, will avert unplanned unit shutdowns and minimize the potential need for expedited licensing actions seeking approval of more completion time.

   This change will allow some maintenance activities that improve EDG reliability to be performed on-line which would otherwise require performance during a refueling outage. On-line preventive maintenance and scheduled overhauls provide the flexibility to focus more quality resources on any required or elective DG maintenance. For example, during refueling outages, resources are required to support many systems; during online maintenance, plant resources can be more focused on the DG overhaul. The extended CT associated with an inoperable DG will improve the effectiveness of the allowed maintenance period. A significant portion of on-line maintenance activities is associated with preparation and return to service activities, such as, tagging, fluid system drain down, fluid system fill and vent, and cylinder block heat-up. The duration of these activities is relatively constant. A longer Required Action CT duration allows more maintenance to be accomplished during a given on-line maintenance period and therefore would improve maintenance efficiency.

   Performance of more DG maintenance on-line will improve DG availability during plant refueling outages. Performing more DG overhaul activities on-line should reduce the risk and synergistic effects on risk due to DG unavailability occurring concurrently with other activities and equipment outages during a refueling outage.

2. Reduction in Unnecessary Burden
These proposed changes provide a reduction in unnecessary burden, because they:

- Avert unplanned unit shutdowns and minimize the potential need for expedited licensing actions seeking approval of more completion time.
- Increase the time to perform troubleshooting, repair, and testing of an inoperable DG during Modes 1 through 4, which will enhance the safety and reliability of equipment and personnel.
- Allow additional time to perform routine maintenance activities on the DG in Modes 1 through 4, enhancing the ability to focus quality resources on the activity, improve maintenance efficiency, and improve DG availability during plant refueling outages.

## 3.0 TECHNICAL EVALUATION

For BFN Units 1, 2, and 3, TVA is proposing to extend the TS allowed CT for an inoperable DG from 7 days to 14 days and to extend the maximum CT that a unit may be in Conditions A and B of TS 3.8.1 concurrently or simultaneously from 14 days to 21 days. This license amendment request includes an integrated review and assessment of plant operations and deterministic design basis factors. The proposed change includes the requirement for availability of two TDGs to compensate for an extra 7 days of DG inoperability.

### 3.1 Introduction

The proposed changes will allow a CT of 14 days for DG maintenance or testing activities, and a total CT of 21 days for concurrent or simultaneous entries in Conditions A and B of TS 3.8.1. This proposal will allow an additional 7 days beyond the current TS allowed CTs and avoid or minimize TS required plant shutdown time due to DG maintenance or testing, when the TDGs are available to the ESF bus with the inoperable DG.

Site-specific experience has shown that the current CT for restoring a DG to an operable status is not adequate to complete these activities.

### 3.2 Background

**BFN Electrical System Description**

#### 3.2.1 Offsite Power Distribution

The TVA transmission system is a diverse and dependable system due to the large generating capacity of TVA, the high number of transmission lines, and multiple interconnections. This results in a highly stable and reliable off-site power supply system for BFN.

Off-site power is delivered to the site via seven 500-kV and two 161-kV transmission lines. These lines feed a 500-kV switchyard and a 161-kV switchyard as described in detail in Chapter 8.3 of the BFN Updated Final Safety Analysis Report (UFSAR) (Reference 6.1). The 500-kV switchyard includes seven line bays and three transformer bays, and is designed to minimize the effects of the failure of individual items of equipment so any single probable event will not prevent the 500-kV system from providing off-site power. The 500-kV yard has two main buses, which are physically separated, and each bus has two sections connected by a disconnect. Each transformer can back feed from either bus. 4.16-kV station service is provided via the unit Main Transformers and two Unit Station Service Transformers on each unit.

### 3.2.2 Grid Reliability

Regarding the likelihood of needing DGs due to the loss of offsite power or degraded voltage conditions, TVA's power system provides some of the most reliable electric power in North America. TVA's regional transmission grid spans portions of seven states. TVA's nuclear plants generate approximately 30 percent of TVA's net power. The remaining 70 percent of power generation comes from reliable fossil and hydroelectric plants, and pumped storage.

In actions taken in response to Generic Letter 2006-02, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power" (Reference 6.4), protocols have been put in place to improve communications between TVA grid operators and BFN operating staff. This includes daily communications regarding plant activities and TVA system grid activities, coordination of scheduling activities on matters related to off-site power and on-site power systems, contingency planning for degraded configurations, and prompt notification of plant operators in the event of degraded grid situations.

Adverse weather contingency procedures have also been established for meteorological conditions that could potentially affect offsite power availability. Operators will monitor weather forecasts each shift. Weather conditions will be evaluated prior to intentionally entering the extended DG outage and will not be entered if official weather forecasts are predicting severe conditions (tornado or thunderstorm warnings). If severe weather or grid instability is expected after a DG outage begins, station managers will assess the conditions and determine the best course for returning the DG to an operable status.

### 3.2.3 Onsite Emergency Power System

BFN is a three-unit plant, with each unit being a General Electric (GE) Boiling Water Reactor (BWR) 4 with a Mark I containment. All Alternating Current (AC) loads necessary for the safe shutdown of the plant under non-accident and accident conditions are fed from the standby AC power supply and distribution system.

The standby AC supply and distribution system for BFN Units 1 and 2 includes four DGs (A, B, C, and D), four 4160V shutdown boards (4.16kV-SDBD-A, B, C, and D), four 480V shutdown boards (480V-SDBD-1A, 2A, 1B, and 2B), eight 480V Reactor Motor Operated Valve (RMOV) boards, four Motor Generator (MG) sets, and two 480V diesel auxiliary boards.

The standby AC supply and distribution system for BFN Unit 3 includes four DGs (3A, 3B, 3C, and 3D), four 4160V shutdown boards (4.16kV-SDBD-3EA, 3EB, 3EC, and 3ED), two 480V shutdown boards (480V-SDBD-3A, and 3B), five 480V RMOV boards, four MG sets, and two 480V diesel auxiliary boards.

The standby AC supply and distribution systems are connected in a manner which supplies unitized power to Units 1/2 and Unit 3 electrical loads. In addition to the unitized electrical loads, shared (common) systems between all three units are an integral part of the BFN plant configuration. Detailed discussions of the shared systems are given in Appendix F of the Updated Final Safety Analysis Report (UFSAR) (Reference 6.2). The safety related shared systems which are pertinent to the DG TS CT evaluation are the Residual Heat Removal Service Water (RHRSW), Emergency Equipment Cooling Water (EECW), Standby Gas Treatment, (SBGT), and Control Room Emergency Ventilation (CREV).

The eight DGs provide a standby power supply used on loss of the normal Auxiliary Power System Supplies. Each of the DGs is assigned to one 4.16kV Shutdown Board. Provision is made for the interconnection of 4.16kV Shutdown Board A (Units 1/2) with 4.16kV Shutdown Board 3EA (Unit 3). Similar interconnections have been provided between Units 1/2 and Unit 3 boards B and 3EB, C and 3EC, and D and 3ED. It is possible, using the 4.16kV bus tie board (UFSAR Figure 8.4-2), to make any DG available to any 4.16kV Shutdown Board.

The non-safety related TDGs will be connected to the 4.16kV Bus Tie Board, separated from each 1E 4.16kv ESF boards by 3 manually operated, normally open breakers in series. Upon an SBO event, the

TDGs will be started and connected to the ESF board associated with the inoperable DG by manually closing the appropriate Bus Tie Board breakers and a 4.16kv Shutdown Board breaker, supplying power to the deenergized Shutdown Board.

Below the 4.16kV level, the system is basically unitized, having two 480V Shutdown Boards (with associated 480V RMOV boards) and two DG auxiliary boards (unitized between Units 1/2 and Unit 3). The two 480V Shutdown Boards, one physically isolated from the other, have independent supplies from different 4.16kV boards; in addition, each has a backup supply from a third 4.16kV board. The four 480V diesel auxiliary boards, which provide common services to the DGs, are similar to the unit 480V Shutdown Boards in respect to physical and electrical separation and supply. The remaining DGs supplying power to the backup emergency 480v transformer supply could be aligned to supplement 480V loads normally carried by a DG under maintenance, if required. For example, 480V Shutdown Board 3A can be transferred from DG 3A to the emergency supply that is fed from DG 3B.

While these boards have backup emergency supplies, these loads will not be pre-aligned to the emergency supply during the associated DG maintenance outage. This is primarily because: (1) this configuration often requires crossing divisional separation and results in increased risk of a single failure of an off-site circuit causing a loss of both divisions, and (2) the act of transferring the boards poses unnecessary risk to the operating units.

Additional capacity can be attained for the associated Unit 1/2 Shutdown Board by paralleling a Unit 3 DG. To accomplish this, a Unit 3 4.16kV Shutdown Board that can be stripped of all of its loads is selected. The selected Unit 3 4.16kV Shutdown Board, supplied by a Unit 3 DG, is then stripped of its loads and paralleled with the corresponding Unit 1/2 4.16kV Shutdown Board. This alignment will result in a Unit 3 DG and a Unit 1/2 DG supplying power to the Unit 1/2 4.16kV Shutdown Board with the inoperable Unit 1/2 DG. The detailed process for performing this task is documented in Abnormal Operating Instruction 0-AOI-57-1A, "Loss of Offsite Power (161 and 500 KV)/Station Blackout, Attachment 11, Operating Two RHR Pumps on One Unit 1/Unit 2 4.16kV Shutdown Board."

In the event of a loss of all off-site power (LOOP) and the concurrent inoperability of a Unit 3 DG, the de-energized 4.16kV Shutdown Board can be supplied through a Bus Tie from another Unit 3 DG. This configuration would be a compensatory measure and is not a normal configuration for Unit 3 DGs.

In the event of an SBO and the concurrent inoperability of a unit's DG, the TDGs will provide an independent AC source to any of the 8 ESF boards. Per procedure and TS, the TDGs will be supporting only one inoperable DG at a time during an extended 14-day CT.

### 3.2.4 Differences between the BFN Units and AC Power Configurations

Unit sharing and interactions are discussed and evaluated in UFSAR Appendix F. Relevant sections regarding standby AC power supply and distribution systems are discussed below. Discussion is also provided on unit differences with regard to the AC Power Configurations.

For Units 1 and 2, the system is composed of four independent DG units coupled as an alternate source of power to four independent 4.16kV boards. There are four additional DG units coupled as an alternate source of power to the four Unit 3 4.16kV boards. Any given Unit 1 and Unit 2 4.16kV board has two RHR pumps, each assigned to a different unit. Thus, the four Shutdown Boards supply four RHR pumps on each unit. Any given Unit 3 4.16kV board has one RHR pump; thus, the four Unit 3 boards also supply four RHR pumps. Similarly, the four Unit 1 and Unit 2 Shutdown Boards power eight Core Spray pumps, and the Unit 3 Shutdown Boards power four Core Spray pumps. Two such pumps operating in parallel on the same Core Spray loop are required for Core Spray on a particular unit.

For Units 1 and 2, on loss of supply from a 4160V shutdown bus, in the absence of an accident signal, there is automatic transfer of the shutdown board to the alternate shutdown bus with automatic return when the normal supply voltage is restored. The Unit 3 design does not include these shutdown buses.

For Units 1 and 2 only, to prevent overloading the shared Unit 1 4.16kV shutdown boards during coincident combinations on both units, the RHR Low Pressure Core Injection and Core Spray systems will initiate the ECCS preferred pump logic to dedicate the Division I 4.16kV shutdown boards and their associated pumps to Unit 1. The Division II shutdown boards and their associated pumps are dedicated to Unit 2. This ECCS preferred pump logic does not exist on Unit 3.

As described in the UFSAR Section 8.4, the 480V safety related boards are provided with manual transfer capability, with the exception of the Units 2 and 3 RMOV Boards D and E that also have automatic transfer capability. For Unit 1 only, the Low Pressure Coolant Injection (LPCI) Motor Generator-Sets have been removed. 480v RMOV Boards 1D and 1E have been abandoned in place and the loads redistributed. The DGs loads have been evaluated for normal and alternate alignments, including the automatic transfer of the RMOV Boards D and E in Units 2 and 3. Therefore, the remaining operable DGs are not susceptible to overload conditions from automatic transfers due to the extended DG outage and a loss of off-site power.

### 3.2.5 Transients and Accidents

The ECCS pumps powered by the on-site DGs are the 2000 hp Residual Heat Removal Pumps and the 600 hp Core Spray Pumps. DG 3A, 3B, C, and D also supply power for a 400 hp RHRSW pump (pump A3, C3, B3, D3) dedicated to EECW. DG A, B, 3C, and 3D can also supply power for a 400 hp RHRSW pump dedicated to EECW if the RHRSW swing pumps (pump A1, C1, B1, D1 respectively) are aligned for EECW. For a Design Basis Accident (DBA) Loss of Coolant Accident (LOCA) with LOOP, each of these pumps (RHR, CS, EECW) will sequence on automatically. The RHR pumps are sized on the basis of the flow required during the low pressure coolant injection (LPCI) mode of operation, which is the mode requiring the maximum flow rate. Therefore, the most limiting accident with respect to DG capability is the DBA LOCA consisting of a double ended recirculation pipe break with simultaneous loss of offsite power. The most limiting transient with respect to DG capability is the loss of offsite power. This transient is bounded by the DBA discussed below.

<u>DBA < 10 Minutes</u>
For a LOOP/LOCA with one DG out of service for maintenance and no additional single failures assumed, the 7 remaining DGs will start and the ECCS equipment associated with the accident unit will automatically sequence on. All in-service DGs in the plant will be started on an accident signal in any unit as a pre-emergency action in case of a subsequent loss of offsite power. If the pipe break involves the recirculation discharge line, then one RHR loop will be ineffective for vessel injection due to the location of the break. The limiting DG out of service (OOS) would be the one supplying the 480 RMOV Boards 1A or 1B for the ECCS division opposite the broken discharge loop for a Unit 1 accident. On Units 2 and 3, 480 RMOV Boards D and E automatically transfer to an alternate supply and this failure combination is less limiting since LPCI injection valves for both divisions remain available. The remaining equipment for Core Cooling would be one loop of Core Spray consisting of 2 pumps.

<u>DBA > 10 Minutes</u>
After initial core reflood, operators are assumed to secure all but one loop of Core Spray for vessel injection to establish long term core cooling. Operators would then establish at least 2 RHR pumps and 2 RHRSW pumps in containment cooling mode (containment spray or suppression pool cooling). At this time operators on the other units which experienced only a loss of offsite power would maintain core cooling with high pressure systems (High Pressure Coolant Injection (HPCI) or Reactor Core Isolation Cooling (RCIC)) and establish suppression pool cooling. With a Unit 1/2 DG OOS and a LOCA on Unit 1 or 2, only one of two RHR and RHRSW pumps needed to maintain suppression pool temperature within design basis limits would be available for the non-accident unit. In some cases, the 480V Boards needed to establish Suppression Pool cooling on the non-accident unit would be lost. To restore the 480V Boards and to establish the second RHR and RHRSW pumps needed for suppression pool cooling in the non-accident unit, operators would coordinate to cross connect a Unit 3 DG to the 4.16kV Shutdown Board associated with the OOS DG. Operator coordination and cross connecting a Unit 3 DG

to a Unit 1/2 4.16kV Shutdown Board can be performed in the Main Control Rooms and this evolution can be performed in less than one hour (most likely accomplished in less than 15 minutes). Analysis has been performed that demonstrates that this time is adequate to maintain the suppression pool temperature within design basis limits.

For the non-accident units, the preferred method for cooling would be to establish shutdown cooling if it is available. Operators would begin to reduce Reactor Pressure Vessel pressure at a 100°F/hr cool down rate (required when suppression pool temperature reaches 120°F) using Safety Relief Valves. When pressure is reduced to less than the RHR low pressure permissive pressure, the RHR pump is placed in shutdown cooling, thus terminating heat input to the containment. Calculations show that suppression pool temperature can be maintained within design basis limits of 187°F if shutdown cooling is established before 11,100 seconds (~3.1 hours).

DG A Out-Of-Service (Unit 1 LOCA)
In the event of a DBA LOCA on Unit 1 with DG A out of service, 4.16kV Shutdown Board A is initially lost for a LOOP event. It is noted that Division I of 480V loads would be lost in Unit 1 and both of the A train RHRSW Pumps would be lost. For LOOP/LOCA on Unit 1, DG C/D, 4.16kV Shutdown Board C/D, RHR 1B/1D, Core Spray 1B/1D, RHRSW B/D and Division II 480V loads would be used to mitigate the accident.

Only one of two RHR and RHRSW pumps needed to maintain suppression pool temperature within design basis limits would be available for Unit 2. Unit 2 operators would maintain core cooling with HPCI or RCIC. Unit 2 operators would establish suppression pool cooling with the available RHR Pump 2C fed from DG B and coordinate with Unit 3 to cross connect DG 3A to 4.16kV Shutdown Board A to obtain the second needed Unit 2 RHR/RHRSW pumps needed for suppression pool cooling.

Unit 3 operators would maintain core cooling with HPCI or RCIC and then establish suppression pool cooling using RHR 3B/3D and RHRSW B/D and 480V Division II. Unit 3 Operations would place 480V Shutdown Board 3A (Division I) on alternate so that it is supplied by DG 3B. All Unit 3 loads would be removed from 4.16kV Shutdown Board 3EA, including removing EECW Pump A3 after verification that two other EECW pumps are in service. Then DG 3A and 4.16kV Shutdown Board 3EA would be connected to 4.16kV Shutdown Board A using the inter-tie breakers. This restores power to 4.16kV Shutdown Board A and the affected equipment including Unit 1 Division I 480V loads, RHR Pump 2A and both A train RHRSW pumps which could then be used to support Unit 2 shutdown. This configuration provides at least two RHR and two RHRSW pumps in each unit as required.

DG B Out-Of-Service (Unit 1 LOCA)
In the event of a DBA LOCA on Unit 1 with DG B out of service, 4.16kV Shutdown Board B is initially lost for a LOOP event. It is noted that Division I of 480V loads would be lost in Unit 2 and both of the C train RHRSW Pumps would be lost. For LOOP/LOCA on Unit 1, DG C/D, 4.16kV Shutdown Board C/D, RHR 1B/1D, Core Spray 1B/1D, and RHRSW B/D and Division II 480V loads would be used to mitigate the accident.

Only one of two RHR and RHRSW pumps needed to maintain suppression pool temperature within design basis limits would be available for Unit 2. Unit 2 operators would maintain core cooling with HPCI or RCIC. Unit 2 operators would not be able to establish suppression pool cooling with the available RHR Pump 2A fed from DG A since Unit 2 480 Division I loads are lost. Unit 2 operators would coordinate with Unit 3 to cross connect DG 3B to 4.16kV Shutdown Board B to obtain the Unit 2 Division I 480V loads and RHR/RHRSW pumps needed for suppression pool cooling.

Unit 3 operators would maintain core cooling with HPCI or RCIC and then establish suppression pool cooling using RHR 3B/3D and RHRSW B/D and 480V Division II. All Unit 3 loads would be removed from 4.16kV Shutdown Board 3EB, including removing EECW Pump C3 after verification that two other EECW pumps are in service. Then DG 3B and 4.16kV Shutdown Board 3EB would be connected to 4.16kV Shutdown Board B using the inter-tie breakers. This restores power to 4.16kV Shutdown Board B and the affected equipment including Unit 2 Division I 480V loads, RHR Pump 2C and both C train RHRSW

pumps which could then be used to support Unit 2 shutdown. This configuration provides at least two RHR and two RHRSW pumps in each unit as required.

DG C Out-Of-Service (Unit 1 LOCA)
In the event of a DBA LOCA on Unit 1 with DG C out of service, 4.16kV Shutdown Board C is initially lost for a LOOP event. It is noted that Division II of 480V loads would be lost in Unit 1 and EECW pump B3 and one pump of the B train RHRSW Pumps would be lost. For LOOP/LOCA on Unit 1, DG A/B, 4.16kV Shutdown Board A/B, RHR 1A/1C, Core Spray 1A/1C, and RHRSW A/C and Division I 480V loads would be used to mitigate the accident.

Only one of two RHR and RHRSW pumps needed to maintain suppression pool temperature within design basis limits would be available for Unit 2. Unit 2 operators would maintain core cooling with HPCI or RCIC. Unit 2 operators would establish suppression pool cooling with the available RHR Pump 2D fed from DG D and coordinate with Unit 3 to cross connect DG 3C to 4.16kV Shutdown Board C to obtain the second needed Unit 2 RHR/RHRSW pumps needed for suppression pool cooling.

Unit 3 operators would maintain core cooling with HPCI or RCIC and then establish suppression pool cooling using RHR 3A/3C and RHRSW A/C and 480V Division I. Unit 3 Operations would place 480V Shutdown Board 3B (Division II) on alternate so that it is supplied by DG 3B. After coordination with the accident unit and confirming that the B train of RHR is not required in any unit, all Unit 3 loads would be removed from 4.16kV Shutdown Board 3EC, including removing RHRSW Pump B1. (This would leave the B train of RHR in each unit without RHRSW until cross-ties are made and loads sequenced back on. However, Unit 2 is the only Unit that credits the B train for this scenario.) DG 3C and 4.16kV Shutdown Board 3EC would be connected to 4.16kV Shutdown Board C using the inter-tie breakers. This restores power to 4.16kV Shutdown Board C and the affected equipment including Unit 1 Division II 480V loads, RHR Pump 2B, EECW Pump B3 and RHRSW Pump B2. (One RHRSW Pump in a train is sufficient for one heat exchanger being used in that train. While not required, RHRSW Pump B1 could be restarted on 4.16kV Shutdown Board 3EC if B3 EECW Pump from 4.16kV Shutdown Board C is not in service.) This configuration provides at least two RHR and two RHRSW pumps in each unit as required.

DG D Out-Of-Service (Unit 1 LOCA)
In the event of a DBA LOCA on Unit 1 with DG D out of service, 4.16kV Shutdown Board D is initially lost for a LOOP event. It is noted that Division II of 480V loads would be lost in Unit 2 and EECW pump D3 and one pump of the D train RHRSW Pumps would be lost. For LOOP/LOCA on Unit 1, DG A/B, 4.16kV Shutdown Board A/B, RHR 1A/1C, Core Spray 1A/1C, and RHRSW A/C and Division I 480V loads would be used to mitigate the accident.

Only one of two RHR and RHRSW pumps needed to maintain suppression pool temperature within design basis limits would be available for Unit 2. Unit 2 operators would maintain core cooling with HPCI or RCIC. Unit 2 operators would not be able to establish suppression pool cooling with the available RHR Pump 2B fed from DG C since Unit 2 480V Division II loads are lost. Unit 2 operators would coordinate with Unit 3 to cross connect DG 3D to 4.16kV Shutdown Board D to obtain the Unit 2 Division II 480V loads and RHR/RHRSW pumps needed for suppression pool cooling.

Unit 3 operators would maintain core cooling with HPCI or RCIC and then establish suppression pool cooling using RHR 3A/3C and RHRSW A/C and 480V Division I. Unit 3 operators would confirm that the other trains of Standby Gas Treatment and Control Bay Ventilation are in service and begin shedding loads from 4.16kV Shutdown Board 3ED. After coordination with the accident unit and confirming that the D train of RHR is not required in any unit, all Unit 3 loads would be removed from 4.16kV Shutdown Board 3ED, including removing RHRSW Pump D1. (This would leave the D train of RHR in each unit without RHRSW until cross-ties are made and loads sequenced back on. However, Unit 2 is the only Unit that credits the D train for this scenario.) DG 3D and 4.16kV Shutdown Board 3ED would be connected to 4.16kV Shutdown Board D using the inter-tie breakers. This restores power to 4.16kV Shutdown Board D and the affected equipment including Unit 2 Division II 480V loads, RHR Pump 2D, EECW Pump D3 and RHRSW Pump D2. (One RHRSW Pump in a train is sufficient for one heat exchanger being used in that train. While not required, RHRSW Pump D1 could be restarted on 4.16kV Shutdown Board 3ED if

D3 EECW Pump from 4.16kV Shutdown Board D is not in service.) This configuration provides at least two RHR and two RHRSW pumps in each unit as required.

DG A Out-Of-Service (Unit 2 LOCA)
In the event of a DBA LOCA on Unit 2 with DG A out of service, 4.16kV Shutdown Board A is initially lost for a LOOP event. It is noted that Division I of 480V loads would be lost in Unit 1 and both of the A train RHRSW Pumps would be lost. For LOOP/LOCA on Unit 2, DG C/D, 4.16kV Shutdown Board C/D, RHR 2B/2D, Core Spray 2B/2D, RHRSW B/D and Division II 480V loads would be used to mitigate the accident.

Only one of two RHR and RHRSW pumps needed to maintain suppression pool temperature within design basis limits would be available for Unit 1. Unit 1 operators would maintain core cooling with HPCI or RCIC. Unit 1 operators would not be able to establish suppression pool cooling with the available RHR Pump 1C fed from DG B since Unit 1 480V Division I loads are lost. Unit 1 operators would coordinate with Unit 3 to cross connect DG 3B to 4.16kV Shutdown Board A to obtain the Unit 1 Division I 480V loads and RHR/RHRSW pumps needed for suppression pool cooling.

Unit 3 operators would maintain core cooling with HPCI or RCIC and then establish suppression pool cooling using RHR 3B/3D and RHRSW B/D and 480V Division II. Unit 3 Operations would place 480 Shutdown Board 3A (Division I) on alternate so that it is supplied by DG 3B. All Unit 3 loads would be removed from 4.16kV Shutdown Board 3EA, including removing EECW Pump A3 after verification that two other EECW pumps are in service. Then DG 3A and 4.16kV Shutdown Board 3EA would be connected to 4.16kV Shutdown Board A using the inter-tie breakers. This restores power to 4.16kV Shutdown Board A and the affected equipment including Unit 1 Division I 480V loads, RHR Pump 1A and both A train RHRSW pumps which could then be used to support Unit 1 shutdown. This configuration provides at least two RHR and two RHRSW pumps in each unit as required.

DG B Out-Of-Service (Unit 2 LOCA)
In the event of a DBA LOCA on Unit 2 with DG B out of service, 4.16kV Shutdown Board B is initially lost for a LOOP event. It is noted that Division I of 480V loads would be lost in Unit 2 and both of the C train RHRSW Pumps would be lost. For LOOP/LOCA on Unit 2, DG C/D, 4.16kV Shutdown Board C/D, RHR 2B/2D, Core Spray 2B/2D, and RHRSW B/D and Division II 480V loads would be used to mitigate the accident.

Only one of two RHR and RHRSW pumps needed to maintain suppression pool temperature within design basis limits would be available for Unit 1. Unit 1 operators would maintain core cooling with HPCI or RCIC. Unit 1 operators would establish suppression pool cooling with the available RHR Pump 1A fed from DG A and coordinate with Unit 3 to cross connect DG 3B to 4.16kV Shutdown Board B to obtain the second needed Unit 1 RHR/RHRSW pumps needed for suppression pool cooling.

Unit 3 operators would maintain core cooling with HPCI or RCIC and then establish suppression pool cooling using RHR 3B/3D and RHRSW B/D and 480V Division II. All Unit 3 loads would be removed from 4.16kV Shutdown Board 3EB, including removing EECW Pump C3 after verification that two other EECW pumps are in service. Then DG 3B and 4.16kV Shutdown Board 3EB would be connected to 4.16kV Shutdown Board B using the inter-tie breakers. This restores power to 4.16kV Shutdown Board B and the affected equipment including RHR Pump 1C and both C train RHRSW pumps which could then be used to support Unit 1 shutdown. This configuration provides at least two RHR and two RHRSW pumps in each unit as required.

DG C Out-Of-Service (Unit 2 LOCA)
In the event of a DBA LOCA on Unit 2 with DG C out of service, 4.16kV Shutdown Board C is initially lost for a LOOP event. It is noted that Division II of 480V loads would be lost in Unit 1 and EECW pump B3 and one pump of the B train RHRSW Pumps would be lost. For LOOP/LOCA on Unit 2, DG A/B, 4.16kV Shutdown Board A/B, RHR 2A/2C, Core Spray 2A/2C, and RHRSW A/C and Division I 480V loads would be used to mitigate the accident.

Only one of two RHR and RHRSW pumps needed to maintain suppression pool temperature within design basis limits would be available for Unit 1. Unit 1 operators would maintain core cooling with HPCI or RCIC. Unit 1 operators would not be able to establish suppression pool cooling with the available RHR Pump 1D fed from DG D since Unit 1 480V Division II loads are lost. Unit 1 operators would coordinate with Unit 3 to cross connect DG 3C to 4.16kV Shutdown Board C to obtain the Unit 1 Division II 480V loads and RHR/RHRSW pumps needed for suppression pool cooling.

Unit 3 operators would maintain core cooling with HPCI or RCIC and then establish suppression pool cooling using RHR 3A/3C and RHRSW A/C and 480V Division I. Unit 3 Operations would place 480V Shutdown Board 3B (Division II) on alternate so that it is supplied by DG 3B. After coordination with the accident unit and confirming that the B train of RHR is not required in any unit, all Unit 3 loads would be removed from 4.16kV Shutdown Board 3EC, including removing RHRSW Pump B1. (This would leave the B train of RHR in each unit without RHRSW until cross-ties are made and loads sequenced back on. However, Unit 1 is the only Unit that credits the B train for this scenario.) DG 3C and 4.16kV Shutdown Board 3EC would be connected to 4.16kV Shutdown Board C using the inter-tie breakers. This restores power to 4.16kV Shutdown Board C and the affected equipment including Unit 1 Division II 480V loads, RHR Pump 1B, EECW Pump B3 and RHRSW Pump B2. (One RHRSW Pump in a train is sufficient for one heat exchanger being used in that train. While not required, RHRSW Pump B1 could be restarted on 4.16kV Shutdown Board 3EC if B3 EECW Pump from 4.16kV Shutdown Board C is not in service.) This configuration provides at least two RHR and two RHRSW pumps in each unit as required.

DG D Out-Of-Service (Unit 2 LOCA)

In the event of a DBA LOCA on Unit 2 with DG D out of service, 4.16kV Shutdown Board D is initially lost for a LOOP event. It is noted that Division II of 480V loads would be lost in Unit 2 and EECW pump D3 and one pump of the D train RHRSW Pumps would be lost. For LOOP/LOCA on Unit 2, DG A/B, 4.16kV Shutdown Board A/B, RHR 2A/2C, Core Spray 2A/2C, and RHRSW A/C and Division I 480V loads would be used to mitigate the accident.

Only one of two RHR and RHRSW pumps needed to maintain suppression pool temperature within design basis limits would be available for Unit 1. Unit 1 operators would maintain core cooling with HPCI or RCIC. Unit 1 operators would establish suppression pool cooling with the available RHR Pump 2B fed from DG C and coordinate with Unit 3 to cross connect DG 3D to 4.16kV Shutdown Board D to obtain the second needed Unit 2 RHR/RHRSW pumps needed for suppression pool cooling.

Unit 3 operators would maintain core cooling with HPCI or RCIC and then establish suppression pool cooling using RHR 3A/3C and RHRSW A/C and 480V Division I. Unit 3 operators would confirm that the other trains of Standby Gas Treatment and Control Bay Ventilation are in service and begin shedding loads from 4.16kV Shutdown Board 3ED. After coordination with the accident unit and confirming that the D train of RHR is not required in any unit, all Unit 3 loads would be removed from 4.16kV Shutdown Board 3ED, including removing RHRSW Pump D1. (This would leave the D train of RHR in each unit without RHRSW until cross-ties are made and loads sequenced back on. However, Unit 1 is the only Unit that credits the D train for this scenario.) DG 3D and 4.16kV Shutdown Board 3ED would be connected to 4.16kV Shutdown Board D using the inter-tie breakers. This restores power to 4.16kV Shutdown Board D and the affected equipment including RHR Pump 1D, EECW Pump D3 and RHRSW Pump D2. (One RHRSW Pump in a train is sufficient for one heat exchanger being used in that train. While not required, RHRSW Pump D1 could be restarted on 4.16kV Shutdown Board 3ED if D3 EECW Pump from 4.16kV Shutdown Board D is not in service.) This configuration provides at least two RHR and two RHRSW pumps in each unit as required.

DG 3A Out-Of-Service (Unit 3 LOCA)

In the event of a DBA LOCA on Unit 3 with DG 3A out of service, 4.16kV Shutdown Board 3EA is lost for a LOOP event. It is noted that Division I of 480V loads would be lost in Unit 3 and A3 EECW Pump would be lost. For LOOP/LOCA on Unit 3, DG 3C/3D, 4.16kV Shutdown Board 3EC/3ED, RHR 3B/3D, Core Spray 3B/3D, RHRSW B/D and Division II 480V loads would be used to mitigate the accident. Unit 3 Division I 480V loads could be aligned to alternate supply fed from DG 3B if desired.

Unit 1 and 2 operators would maintain core cooling with HPCI or RCIC. Unit 1 and 2 operators would establish suppression pool cooling with two RHR and two RHRSW Pumps available in each unit.

Two out of four EECW Pumps are required. Three out of four EECW pumps would remain available. This configuration provides at least two RHR and two RHRSW pumps in each unit as required without having to cross connect DGs to 4.16kV Shutdown Boards.

DG 3B Out-Of-Service (Unit 3 LOCA)
In the event of a DBA LOCA on Unit 3 with DG 3B out of service, 4.16kV Shutdown Board 3EB is lost for a LOOP event. It is noted that C3 EECW Pump would be lost. For LOOP/LOCA on Unit 3, DG 3C/3D, 4.16kV Shutdown Board 3EC/3ED, RHR 3B/3D, Core Spray 3B/3D, RHRSW B/D and Division II 480V loads would be used to mitigate the accident.

Unit 1 and 2 operators would maintain core cooling with HPCI or RCIC. Unit 1 and 2 operators would establish suppression pool cooling with two RHR and two RHRSW Pumps available in each unit.

Two out of four EECW Pumps are required. Three out of four EECW pumps would remain available. This configuration provides at least two RHR and two RHRSW pumps in each unit as required without having to cross connect DGs to 4.16kV Shutdown Boards.

DG 3C Out-Of-Service (Unit 3 LOCA)
In the event of a DBA LOCA on Unit 3 with DG 3C out of service, 4.16kV Shutdown Board 3EC is lost for a LOOP event. It is noted that Division II of 480V loads would be lost in Unit 3 and RHRSW Pump B1 would be lost. For LOOP/LOCA on Unit 3, DG 3A/3B, 4.16kV Shutdown Board 3EA/3EB, RHR 3A/3C, Core Spray 3A/3C, RHRSW A/C and Division I 480V loads would be used to mitigate the accident. Unit 3 Division II 480V loads could be aligned to alternate supply fed from DG 3B if desired.

Unit 1 and 2 operators would maintain core cooling with HPCI or RCIC. Unit 1 and 2 operators would establish suppression pool cooling with two RHR and two RHRSW Pumps available in each unit.

One of two B train RHRSW Pumps is required. RHRSW Pump B2 fed from 4.16kV Shutdown Board C remains available. This configuration provides at least two RHR and two RHRSW pumps in each unit as required without having to cross connect DGs to 4.16kV Shutdown Boards.

DG 3D Out-Of-Service (Unit 3 LOCA)
In the event of a DBA LOCA on Unit 3 with DG 3D out of service, 4.16kV Shutdown Board 3ED is lost for a LOOP event. It is noted that one train of Standby Gas Treatment, one train of Control Bay Ventilation, and RHRSW Pump D1 would be lost. For LOOP/LOCA on Unit 3, DG 3A/3B, 4.16kV Shutdown Board 3EA/3EB, RHR 3A/3C, Core Spray 3A/3C, RHRSW A/C and Division I 480V loads would be used to mitigate the accident.

Unit 1 and 2 operators would maintain core cooling with HPCI or RCIC. Unit 1 and 2 operators would establish suppression pool cooling with two RHR and two RHRSW Pumps available in each unit.

One of two D train RHRSW Pumps is required. RHRSW Pump D2 fed from 4.16kV Shutdown Board D remains available. This configuration provides at least two RHR and two RHRSW pumps in each unit as required without having to cross connect DGs to 4.16kV Shutdown Boards.

10 CFR 50, Appendix R
10 CFR 50, Appendix R, "Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979," requires that the shutdown capability must be able to accommodate post-fire conditions involving a loss of off-site power for 72 hours. Because of this requirement, an adequate number of DGs must be available to provide standby AC power to essential safe shutdown components in the event of a fire within the plant.

To protect equipment from damage due to fires caused by "hot work" activities, precautions and requirements have been defined to protect the plant against possible fire damage or loss resulting from the use of spark or heat producing devices. A fire watch shall be posted as required. Open flames or combustion-generated smoke shall not be used for leak testing.

One method of reducing the severity of a fire which might occur in a given area is to maximize the availability of the fire protection equipment, such as a suppression system, a detection system, fire pump, fire hose station, fire hydrant, and fire barriers. Fire protection equipment and fire barriers are to remain fully operational at all times, to the maximum extent possible. A system has been developed and implemented to monitor fire protection impairments in order to assure appropriate compensatory measures are instituted. This system identifies the conditions that require a roving or continuous fire watch system. For areas where the detection is inoperable, the fire watch will be continuous.

For equipment that is unable to perform its intended function, the compensatory actions (described in the BFN Fire Protection Report), as listed below are applicable.

Compensatory Measure A:

Restore the equipment function in 7 days or provide equivalent shutdown capability by one of the following methods:

1) A temporary alteration in accordance with plant procedures that allows the equipment to perform its intended function, or
2) A fire watch in accordance with the site impairment program in the affected areas/zones as specified in Section III.

This compensatory measure is intended to assure safe shutdown capability is restored within 7 days by either restoring the failed equipment function or by taking temporary measures to assure equivalent shutdown capability exists. Equivalent shutdown capability is defined as

1) Providing temporary equipment or procedures which will ensure the out of service equipment function does not affect safe shutdown capability or
2) Providing adequate fire watch capability to ensure fires are prevented and/or discovered in a time frame which will assure the out of service equipment is not needed to support reactor safe shutdown in case of fire.

An hourly fire watch in these areas would provide sufficient assurance that a fire would not occur or would be detected and mitigated before it progresses to an Appendix R fire event. As a result, spurious operations of critical equipment and serious plant degradation will be prevented.

TDG Fire Protection: As part of Maintenance Rule implementation, the TDGs and their equipment will be evaluated by the BFN Fire Operations Department. This will include evaluation of the TDGs, cables, and oil filled transformers for fire hazards, and appropriate compensatory measures will be taken.

Pre-staged firefighting equipment will be available to protect the TDGs while on site. A temporary boundary with associated signs will be installed around the TDGs to keep out unauthorized personnel, and designate the no smoking area.

Increased administrative control will be exercised for any proposed hot work in the vicinity of protected equipment and in the impacted fire zones in accordance with procedure BFN-ODM-4.18, "Protected Equipment," prior to entering the extended CT and maintained for the duration of the CT.

Transient combustible loading in the impacted fire zones (the TDGs and their temporary 480v/4160v transformers staging area) will be reviewed and any unnecessary transient combustibles will be removed. No elective maintenance will be performed on fire detection or fire suppression equipment that will cause the fire detection or fire suppression equipment in the impacted fire zones to be inoperable for the duration of the extended CT.

Station Blackout (SBO)

The SBO coping duration for BFN is four hours. SBO is postulated as the failure of the two DGs that normally feed a respective unit's 480V AC shutdown boards concurrent with the LOOP. Coping strategy is to shutdown the blacked-out unit with equipment powered from the 250V DC battery system.

Alternate AC power from DGs in the non-blacked-out units will be made available to power additional required HVAC and common loads. As set forth in Nuclear Utility Management and Resource Council (NUMARC) 87-00, "Guidelines for and Technical Basis for NUMARC Initiatives for Addressing Station Blackout at Light Water Reactors," Appendix B (Reference 6.3), the AAC will be available within one hour through existing cross-ties.

The 250V DC unit batteries 1, 2, and 3 are adequate to supply the required Unit 1, Unit 2, and Unit 3 loads for the coping duration of four hours. SBO on Unit 2 is the loss of DGs B and D and loss of DGs A and C for SBO on Unit 1. SBO on Unit 3 is the loss of DGs 3A and 3C. Considering the failure of one DG in each of the non-blacked out units (A or C for Unit 1, B or D for Unit 2, and 3A or 3C for Unit 3), and an additional failure of DG 3B or 3D, a minimum of three DGs remain available for SBO. These provide sufficient power to supply required HVAC and common loads.

Due to the large number of diverse generating units and strong interconnections, the likelihood of the transmission system causing the LOOP is considered to be extremely remote. Off-site power is delivered to the site via seven 500-kV and two 161-kV transmission lines. These lines feed a 500-kV and a 161-kV switchyard as described in detail in Chapter 8.3 of the UFSAR (Reference 6.4). The large number of 500 kV and 161 kV transmission lines and the physical separation of the lines and transformer bays minimize the likelihood of power loss due to loss of transmission lines. Additionally, during this evolution, the protection of the switchyard and cooperation with TVA Transmission helps to minimize risk of the SBO event. As stated in the TVA response to Generic Letter 2006-02 dated April 3, 2006 (Reference 6.7), "TVA's hydroelectric plants reduce the risk of prolonged LOOP since TVA's three Nuclear Power Plants (NPPs) are located along the Tennessee River near hydroelectric stations. The fast start capability of hydroelectric, their locality, and TVA's reservoir system reduces the risk of prolonged LOOP since the hydroelectric plants can be isolated from the regional grid and aligned to TVA's NPPs. This capability provides a means for fast recovery from a grid blackout event."

The BFN configuration results in a favorable off-site power categorization for BFN for 10 CFR 50.63, "Loss of all alternating current power," i.e., SBO rule, applicability. NUMARC 87-00 (Reference 6.3) criteria classifies BFN as an Independence Group I 1/2 category site which is the least susceptible category to LOOP events due to grid-related disturbances. This favorable categorization is based on physical separation of BFN switchyard and off-site transmission lines. BFN is categorized as an Extremely Severe Weather Group 1 site which places BFN in the category of plants least likely to lose off-site power because of extremely severe weather. The Severe Weather category for BFN is Group 2 which is the second most favorable category out of five possible groups with respect to the probability of losing off-site power due to severe weather. With regard to the SBO rule, BFN has been categorized by NRC as an Emergency Alternating Current Category "C" plant. This classification was based on requirements for shutting down all three units for an extended period following a LOOP. This "C" category translates to a SBO coping duration of four hours and a DG target reliability of 0.95 for BFN.

These three factors combine to result in an Off-site Power Design Characteristic Group of P1 for BFN, which is the category of plants with the least susceptibility for LOOP events. NRC has previously accepted this characterization.

While BFN was not licensed in accordance with the Standard Review Plan (SRP), a review of NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," Section 8.4, III.3.O.iv (Reference 6.8), *"When an SBO occurs at one unit of a multiunit site, the EAC power source(s) and the redundant EAC power source(s) are unavailable. An SBO on one unit does not assume a concurrent single failure; however, the remaining unit(s) should still meet the normal operating single failure criteria"* suggests that BFN would incur a loss of off-site power coupled with the failure of 4

out of 8 DGs (2 on SBO Unit and 1 each on non-SBO Units as their single failure). Since DG 3A and 3C normally feed the 480V power system for Unit 3, one of these DGs are assumed failed if Unit 3 is a non-SBO unit and both of these DGs are assumed failed when Unit 3 is the SBO unit. DGs 3B and 3D for SBO supply loads which are common. Therefore, the BFN commitment to also fail one of the DG 3B or 3D in addition to the failures taken on DG 3A and/or 3C could be considered conservative with respect to the SRP requirements discussed above. If the additional failure of either 3B or 3D were not postulated, an additional available DG for SBO provides added flexibility with respect to the requested increased DG outage time.

For SBO, a consideration with respect to the DG extended Completion Time is EECW availability. As previously described, it is possible, through breaker ties to make any DG available to any 4.16kV Shutdown Board. Two EECW pumps are required to support the BFN DGs. The BFN design provides four dedicated EECW pumps fed from separate 4.16kV Shutdown Boards. In addition, four RHRSW pumps are available to be aligned for EECW if needed and not required for the RHRSW system. This redundancy in EECW design along with the flexibility to tie any DG to any 4.16kV Shutdown Board provides BFN the ability to ensure the DGs have adequate cooling for SBO. EECW pumps A3, B3, C3 and D3 are automatically started when their corresponding 4.16kV Shutdown Board (3EA, C, 3EB, and D respectively) is re-energized following a loss of power.

For three of the possible twenty-four SBO scenarios described in the BFN UFSAR, the available DGs for those three scenarios would not result in any immediately available EECW pumps at the beginning of the event. With no cooling available the responding DGs would eventually overheat and be required to be shutdown. If the DG removed from service happened to be one of the DGs that would have provided EECW automatically (i.e., DG 3A, C, 3B, D), operating procedures provide instruction to cope with the scenario where there are no EECW pumps at the beginning of the event.

The TDGs will serve as a supplemental AC power source during an SBO condition during an extended period of DG inoperability up to 14 days. The TDGs will not meet Class IE or safety-related system requirements, but will provide on-site AC capacity beyond that assumed in the preceding discussion to mitigate an SBO event. By procedure, the TDGs will restore one 4.16kV Shutdown Board supporting the ESF loads of a single inoperable DG.

### 3.2.6 Temporary Diesel Generators

**TDG System Description**
All details of the BFN TDGs are still not finalized, but the current descriptions are noted below.

TDG Separation, Connection, Design, Sizing, Operation and Testing:
The TDG alternate AC power source consists of two temporary 1.62 MWe DGs that synchronize with each other automatically, with both TDGs supplying the 4.16kV Bus Tie Board, in parallel. Each Class 1E BFN permanent DG is rated at 2.6 MWe continuous load, much less than the capacity of two TDGs operating in parallel with combined capacity of 3.2 MWe. The TDGs will be commercial-grade, non-safety related portable units. They will be installed inside the plant protected area, in a different area from the switchyard area that provides the offsite TS AC power sources to the units. The TDGs components will be physically separated from safety-related 1E 4.16kV ESF components, separated from the DGs, and separated from the two preferred offsite power sources for all of BFN units. Furthermore, the TDGs will be separated from the Class 1E power system by three manually operated, normally open, circuit breakers in series, one of which will be a Class 1E circuit breaker located at the Class 1E ESF bus. These three normally open breakers, separating the TDGs from the 1E busses, will only be closed after a SBO event, in accordance with approved BFN procedures.

The TDGs will be equipped with voltage regulators and speed governors to maintain the steady state voltage and frequency output within prescribed limits, which will be bounded by the limits applied to the safety-related DGs. The TDGs supplier will be required to demonstrate the capability to maintain voltage and frequency equal to or better than the safety-related DGs during starting of block and large motor loads.

The electrical output of the TDGs will be connected (in parallel) to the 4.16kV Bus Tie Board. The 4.16kV Bus Tie Board, will be connected to the 4.16kV Shutdown Board with the OOS DG via a manual breaker at the Bus Tie Board and a Class 1E Breaker at the 4.16kV Shutdown Board.

The cable connections from the TDGs electrical output will be routed above ground to 480-4160V step up oil filled transformers. Cables from the transformers to the in plant 4.16 kV Tie Bus Board are routed above ground to Manhole "E". Once inside the manhole, the cables are routed below ground to the Bus Tie Board.

After an SBO, an Operator will manually start (and stop) the TDGs locally. No TDGs control will be available in the Control Room. Upon the first TDG attaining rated speed and voltage, the second running TDG will automatically synchronize with the first. Operator action will be required to tie the TDGs output to the 4.16 kV Bus Tie Board by closing breaker 1934. The TDGs combined electrical output will be available for connection to the de-energized Shutdown Board after operators open all load breakers at the deenergized 4.16kV Shutdown Board. Next, operators will manually close two additional (in-series) breakers, one at the Bus Tie Board, one at the Shutdown Board, re-energizing the deenergized Shutdown Board.

Once the deenergized Shutdown Board is reenergized by the TDGs, the unit ESF loads can be started from the respective unit's control room in accordance with the BFN SBO EOP/AOP.

Since the means of supplying power from the TDGs to the ESF buses is essentially a "dead bus" transfer (the closing of 3 manually operated, normally open breakers, after a SBO), operation of the TDGs cannot cause a transient in the 1E power distribution system that could trip an operating unit. There will be no direct interface between the TDGs and the DGs, or between the TDGs and the 1E preferred offsite power supply. The TDGs will be connected only to one Shutdown Board at a time in accordance with approved procedures, for the Shutdown Board with the inoperable DG.

Protection from common cause failures between the DGs and TDGs is provided by physical separation, difference in DG manufacturers, difference in design, the use of separate fuel oil tanks, difference in operating and maintenance procedures.

BFN "Engineering Procedure for TDGs Initial Acceptance Testing" will direct a load test of the TDGs initially after acceptance from the TDGs rental vendor and once per 18 months (while the TDGs are in TVA's custody) to ensure the TDGs' ability to accept, accelerate, and run assigned loads. The same procedure will direct routine preventative maintenance and a monthly unloaded test run, while the TDGs are on site, but only during periods when the TDGs are not credited as available during the extended CT.

After the TDGs are returned to the vendor, and if the TDGs are again needed at BFN to support an extended DG CT, the initial acceptance testing described above will be re-performed to ensure the TDGs' availability .

TDG Housing, Fuel, Refueling, Lubrication Oil, Consumable Spares:
Each TDG has a closed loop radiator cooling system, with engine and generator control panels, output circuit breaker, and miscellaneous support systems and devices.

A 40' truck trailer is the TDG housing, designed to shield the TDG from normal weather conditions. The TDG components will be monitored for fire hazards during Assistant Unit Operator (AUO) and Fire Operations rounds when the extended CT is to be used. The TDG trailer is not seismically protected nor is the trailer rated for severe inclement weather.

Each TDG will be mounted on a fully enclosed truck trailer rig, complete with a 1000 gallon diesel fuel tank sufficient for 10 hours of running time at 100% rated capacity. Furthermore, an additional 8 days of on-site fuel supply can be provided for each TDG via either of the 60% full onsite fuel oil storage tanks (FOSTs). Required actions during a CT greater than 7 days will be to verify the TDGs fuel tanks are at

least 90% full and to keep one FOST at least 60% full. An Operations procedure will direct this surveillance. Each TDG will consume ~2400 gallons of fuel oil per day; the combined consumption will be 4800 gallons per day. A modification will be made to the FOSTs for an independently powered transfer pump and fuel hoses to refuel the TDGs from the FOST after an SBO event.

Each FOST has a capacity of 71,000 gallons. At >60% full, 42,600 gallons will provide enough fuel for greater than 8 days of running the TDGs.

The TDG lubrication oil consumption at full load is 1 quart per hour, per TDG. The TDG(s) are equipped with an external lubrication oil reservoir that will automatically replenish the engine oil. The reservoir holds approximately 80 quarts, enough for 80 hours of continuous operation. Consumable such as lubrication oil and engine coolant will be available, sufficient for an extended TDG run.

The recommended service interval for the TDG is 500 hours, which would give a run time of 20 days. The TDGs can be run for 28 continuous days before being shut down for routine oil and filter change. An Engineering procedure will have guidance for contacts for emergency services/parts/repairs.

TDG Availability:
The TDGs will be operated and maintained according to approved procedures. BFN "Engineering Procedure for TDGs Initial Acceptance Testing" will direct a load test of the TDGs initially after acceptance from the TDGs rental vendor and once per 18 months (while the TDGs are in TVA's custody) to ensure the TDGs' ability to accept, accelerate, and run assigned loads. The same procedure will direct routine preventative maintenance and a monthly unloaded test run, while the TDGs are on site, but only during periods when the TDGs are not credited as available during the extended CT. If the TDGs are needed again after being out of TVA control on site, TVA will re-perform the acceptance testing prior to entering the next planned DG inoperability that exceeds 7 days.

In determining the appropriate frequency for TDGs load testing, TVA has utilized existing guidance for a Station Blackout Alternate AC (AAC) power source. The 18-month testing interval is consistent with the guidance in NUMARC 87-00 (Reference 7) Appendix B, Item B.10, which would require AAC testing at least every refueling outage. Regulatory Guide 1.155 (Reference 8) paragraph 3.3.5.5 states only that an AAC power system should be tested periodically. Following initial verification of the TDGs availability, the proposed TS will require ongoing verification of availability every 12 hours.

While the TDGs are onsite, they will be cordoned off and routinely monitored by AUOs, Fire Operations, and Security personnel commensurate with their intended function. In addition, the TDGs will be designated as protected equipment when they are credited as available for extending a DG CT to 14 days. The BFN on-line risk procedure implementing 10 CFR 50.65 requires that any work activity in a protected equipment area be reviewed to determine if the activity may cause an adverse impact on the protected equipment. If the activity is determined to result in an adverse impact, the work may not proceed unless risk assessment is performed. This process would preclude performance of elective maintenance on the TDGs when they are credited as available for extending a DG CT.

The marked-up TS Bases included for information require TDG availability as follows:

1) The combined loading capability has been demonstrated to exceed that of the inoperable DG. This demonstration must have been performed after being brought onsite and within the past 18 months. The Required Action evaluation is met with an administrative verification of this prior testing.
2) The corresponding control equipment and interconnecting cabling supplying power to the 4.16 kV shutdown board via the 4.16 kV tie-bus associated with the inoperable DG is confirmed available. The Required Action evaluation is met with (a) an administrative verification of prior testing and completion of preventative maintenance activities, and (b) general visual verification that connections and cabling from the TDGs to the Man-Way E are intact;
3) TDG fuel tank levels are verified locally to be ≥ 90%;
4) One fuel oil storage tank level is ≥ 60% and transfer capability is available; and
5) TDGs supporting system parameters for starting and operating are verified to be within required limits for functional availability (e.g., battery state of charge).

TDG Support

The TDGs will be independent of external supports other than fuel oil. The availability of fuel and lubrication oil is included in the analysis. The TDGs will be maintained while it is within TVA control, as directed by an Engineering procedure.

Operator rounds will ensure the replenishment of fuel oil, the functionality of the TDG starting batteries (charging status) and provide an additional level of TDG overall monitoring.

### 3.2.7 Operator Training

Licensed Operators and Assistant Unit Operators (AUO) will be appropriately trained on the purpose and use of the TDGs. A briefing/discussion of the revised TS 3.8.1 and putting TDGs in service will be completed prior to a planned DG inoperability that exceeds 7 days. Operating crews will be briefed on the DG work plan and procedural actions regarding LOOP and SBO.

## 3.3 Traditional Engineering Considerations

For an SBO, the TDGs will be available to power the ESF for the OOS DG. Furthermore, redundant DGs would be available to mitigate the accident, and the units would remain within the bounds of the accident analyses. In addition, there would be no adverse impact to the unit, because the Safety Function Determination Program will be utilized to ensure that cross-train checks are performed to determine if a loss of safety function exists with concurrent equipment inoperability, and ensure the appropriate actions are taken if a loss of safety function is identified. Since the probability of these events occurring concurrently during a elective maintenance window is low, there is minimal safety impact due to the requested extended CTs.

The combination of TDGs for defense-in-depth and safety margin inherent in the Onsite Emergency Power System ensures an emergency supply of power will be available to perform the required safety function. This supports extension of the CTs to allow a DG to be out-of-service for a longer period of time, as discussed further below.

### 3.3.1 Defense-In-Depth

The proposed changes to the CTs, associated with an inoperable DG while the units are in Mode 1-5, maintain the system redundancy, independence, and diversity commensurate with the expected challenges to system operation. The TDGs availability, the other remaining seven operable DGs, offsite power sources, and the associated engineered safety equipment will remain operable to mitigate the consequences of any previously analyzed accident. Otherwise, the Safety Function Determination

Program will require that a loss of safety function be declared, and the appropriate TS Conditions and Required Actions taken.

With a DG inoperable, a loss of function has not occurred. The two TDGs supporting the ESF bus with the inoperable DG, the remaining offsite power sources and seven operable DGs are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure.

Maintenance Rule: In addition to the TS Safety Function Determination Program, the BFN Protected Equipment, the Work Management Program, and the Maintenance Rule Programs provide for controls and assessments to preclude the possibility of simultaneous outages of redundant trains and ensure system reliability.

When a DG is inoperable for the extended CT, the other DGs and two available TDGs with their support equipment will be protected. Only one of the eight DGs will be taken out of service at a time for the planned DG inoperability that exceeds 7 days. If any testing and maintenance activities on the protected equipment must be performed while the planned DG inoperability exceeds 7 days is in effect, a 10 CFR 50.65(a)(4) evaluation will be performed.

Work Control & Scheduling: An extended DG outage will be scheduled and entered only when grid risk conditions are "Green" (as specified in the implementing BFN procedure), and when mild weather conditions are anticipated throughout the 14-day DG outage. The condition of the switchyard, offsite power supply, and the grid will be evaluated prior to and during each shift throughout the extended DG CT.

The Transmission Operator (TRO) system dispatcher will be contacted once per day and BFN will inform the dispatcher of the DG status along with BFN offsite power needs:

i. Prior to entering a planned DG inoperability that exceeds 7 days, BFN Operating Crew will hold discussions with the system load dispatcher to ensure no significant grid perturbations are expected during the planned DG inoperability that exceeds 7 days, and request that the system load dispatcher inform BFN if off site power conditions change during a planned DG inoperability that exceeds 7 days such that significant grid perturbations do occur or become expected.
ii. BFN Grid Operating Guide, TRO-TO-SOP-10.128, provides guidance for monitoring transmission network voltages during normal operation and adjusted the voltage as necessary.

HPCI & RCIC pumps: High Pressure Coolant Injection (HPCI) pump, Reactor Core Isolation Cooling (RCIC) pump, and the Residual Heat Removal (RHR) pump associated with the operable DG will not be removed from service for elective maintenance activities during the planned extended DG inoperability.

Thus, the proposed increase from 7 days to the 14 days CTs, while the TDGs are available, associated with an inoperable DG while the unit is in Mode 1-5, will not alter the assumptions relative to the causes or mitigation of an accident.

3.3.2 Safety Margin

For the extended CTs associated with an inoperable DG while the unit is in Mode 1-5, the plant remains in a condition for which the plant has already been analyzed; therefore, from a deterministic aspect, these changes are acceptable. The 14-day and 21-day CTs are based on a plant-specific analysis using the methodology defined in this license amendment request.

The Maintenance Rule (10 CFR 50.65) requires each licensee to monitor the performance or condition of the DGs to ensure that the DGs are capable of fulfilling its intended functions. If the performance or condition of the DGs do not meet performance criteria, appropriate corrective action is required along with goals to monitor effectiveness of the corrective action.

The overall margin of safety is not decreased due to the extended CTs for the DGs, because:

1. *Codes and standards or their alternatives approved for use by the NRC are met.*
   The design and operation of the DGs are not altered by the proposed extensions in the CTs. Redundancy and diversity of the electrical distribution system will be maintained, because the system design and operation are not altered by the proposed extensions to the CTs. Furthermore, TDGs are installed to mitigate a SBO event for the inoperable DG.

2. *Safety analysis acceptance criteria in the Licensing Basis (e.g., FSAR, supporting analyses) are met or proposed revisions provide sufficient margin to account for analysis and data uncertainty.*
   The safety analysis acceptance criteria stated in the UFSAR are not impacted by the change. The proposed change will not allow plant operation in a configuration outside the design basis. The requirements regarding the DGs credited in the accident analysis will remain the same. Furthermore, TDGs are installed to mitigate a SBO event for the inoperable DG.

Given the above, TVA concludes that safety margins were not impacted by the proposed changes.

3.4 Conclusion

The results of the deterministic evaluation assessment described above provide assurance that the equipment required to safely shut down the plant and mitigate the effects of a design basis accident will remain capable of performing their safety functions when a single DG is out-of-service and the TDGs are in standby in accordance with the proposed CTs.

The proposed CTs with required compensatory actions are consistent with NRC guidance and will continue to provide protection of the public health and safety. The proposed changes meet the following principles:

1. They meet the current regulations.
2. They are consistent with the defense-in-depth philosophy by having TDGs available during a DG extended period of inoperability.
3. They maintain sufficient safety margins.
4. Their impacts will be monitored using performance measurement strategies.

Therefore, based on the above evaluations and conclusions, TVA believes that the proposed changes are acceptable and operation in the proposed manner will not present undue risk to public health and safety or be inimical to the common defense and security.

## 4.0 REGULATORY EVALUATION

### 4.1 Applicable Regulations and Regulatory Criteria

The proposed TS changes have been evaluated to determine whether applicable regulations and requirements continue to be met. To fully evaluate the effect of the proposed change, a deterministic analysis was used. TVA has determined that the proposed CT extensions do not require any exemptions or relief from regulatory requirements, other than the Technical Specifications.

4.1.1 Regulations

10 CFR 50.36, "Technical Specifications," requires that operating licenses for nuclear reactors must include TS that specify Limiting Conditions for Operation (LCOs) for equipment required for safe operation. Based on the assessments presented herein, the proposed changes to the BFN TS have no significant impact on the continued conformance with the requirements of 10 CFR 50.36.

10 CFR 50.65, "Requirements for monitoring the effectiveness of maintenance at nuclear power plants," requires that preventive maintenance activities must be sufficient to provide reasonable assurance that SSCs are capable of fulfilling their intended functions. As it relates to the proposed CT extensions, 10

CFR 50.65(a)(4) requires the assessment and management of the increase in risk that may result from proposed maintenance activities. As discussed previously, the BFN Maintenance Rule program monitors the reliability and availability of the DGs and ensures that appropriate management attention and goal setting are applied based on pre-established performance criteria. The DGs are all currently in the 10 CFR 50.65 (a)(2) Maintenance Rule category (i.e., meeting established performance criteria). The BFN configuration risk management program is consistent with 10 CFR 50.65 (a)(4), and is managed to ensure that risk-significant plant configurations will not be entered for elective maintenance activities, and that appropriate actions will be taken should unforeseen events place the plant in a risk significant configuration during the proposed CTs. Therefore, the proposed extensions of the CTs are not anticipated to result in exceeding the current established Maintenance Rule criteria for the DGs.

10 CFR 50.63, "Loss of all alternating current power," requires that nuclear power plants must be able to withstand a loss of all AC power for an established period of time and recover from a station blackout (see RG 1.155, "Station Blackout," dated August 1988). The proposed extensions to the CTs have no significant effect on the ability to withstand a loss of all AC power and recover from a station blackout.

10 CFR 50.90, "Application for amendment of license or construction permit," addresses the requirements for a licensee desiring to amend its license and the TS incorporated therein. This license amendment request to BFN Units 1, 2, and 3 TS 3.8.1 has been prepared to meet the requirements of 10 CFR 50.90.

4.1.2 Applicable Regulatory Criteria

Regulatory criteria and guidance are consistent with the NRC's "Safety Goal Policy Statement".

Section 19.2 of the SRP states that application should be evaluated to ensure that the proposed change meets the following key principles:

- The proposed change meets the current regulations, unless it explicitly relates to a requested exemption or rule change;
- The proposed change is consistent with the defense-in-depth philosophy;
- The proposed change maintains sufficient safety margins; and
- The impact of the proposed change should be monitored using performance measurement strategies.

Based on the considerations discussed above, the proposed changes been evaluated to verify that:

(1) There is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner;
(2) Such activities will be conducted in compliance with NRC regulations; and
(3) Issuance of the amendment will not be inimical to the common defense and security.

**4.2 Precedent**

Similar TS amendments approved for other plants are listed below.

Callaway, TAC NO. MD7252, Amendment No. 186, 10/31/08
DC Cook, ML050890319, Amendment No. 273 & 291, 09/30/05
FitzPatrick, TAC No. ME1404, Amendment No. 294, 06/08/09
Prairie Island, Units 1 and 2, ML071310023, Amendment No. 178, 05/30/07
Waterford 3, MLOO3734973, Amendment No. 166, 07/21/00

**4.3 Significant Hazards Consideration**

1. Does the proposed amendment involve a significant increase in the probability or consequences of an accident previously evaluated?

   Response: No

The proposed changes do not affect the design of the DGs, the operational characteristics or function of the DGs, the interfaces between the DGs and other plant systems, or the reliability of the DGs. Required Actions and their associated CTs are not considered initiating conditions for any UFSAR accident previously evaluated, nor are the DGs considered initiators of any previously evaluated accidents. The DGs are provided to mitigate the consequences of previously evaluated accidents, including a loss of off-site power.

The consequences of previously evaluated accidents will not be significantly affected by the extended DG CT, because a sufficient number of onsite Alternating Current power sources will continue to remain available to perform the accident mitigation functions associated with the DGs, as assumed in the accident analyses. In addition, as a risk mitigation and defense-in-depth action, an independent AC power source, via two available TDGs, will be available to support the ESF bus with the inoperable DG during a SBO.

Therefore, the proposed changes do not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the proposed amendment create the possibility of a new or different kind of accident from any accident previously evaluated?

   Response: No

   The proposed change does not involve a change in the permanent design, configuration, or method of operation of the plant. The proposed changes will not alter the manner in which equipment operation is initiated, nor will the functional demands on credited equipment be changed. The proposed changes allow operation of the unit to continue while a DG is repaired and retested with the TDGs in standby to mitigate a SBO event. The proposed extensions do not affect the interaction of a DG with any system whose failure or malfunction can initiate an accident. As such, no new failure modes are being introduced. Therefore, the proposed changes do not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does the proposed amendment involve a significant reduction in a margin of safety?

   Response: No

   The proposed changes do not alter the permanent plant design, including instrument set points, nor does it change the assumptions contained in the safety analyses. The standby TDG alternate AC system is designed with sufficient redundancy such that a DG may be removed from service for maintenance or testing. The remaining seven DGs are capable of carrying sufficient electrical loads to satisfy the UFSAR requirements for accident mitigation or unit safe shutdown. The proposed changes do not impact the redundancy or availability requirements of offsite power supplies or change the ability of the plant to cope with station blackout events. Therefore, the proposed changes do not involve a significant reduction in a margin of safety.

Based on the above, TVA concludes that the proposed amendment does not involve a significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of "no significant hazards consideration" is justified.

**4.4 Conclusions**

In conclusion, based on the considerations discussed above, (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

## 5.0 ENVIRONMENTAL CONSIDERATION

A review has determined that the proposed amendment would change a requirement with respect to installation or use of a facility component located within the restricted area, as defined in 10 CFR 20, or would change an inspection or surveillance requirement. However, the proposed amendment does not involve (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amounts of any effluent that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed TS changes meet the eligibility criterion for categorical exclusion set forth in 10 CFR 51.22(c)(9).Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the proposed TS changes.

## 6.0 REFERENCES


6.1 Browns Ferry Nuclear Plant Updated Final Safety Analysis Report, Chapter 8, Electrical Power Systems, Amendment 23

6.2 Browns Ferry Nuclear Plant Updated Final Safety Analysis Report, Appendix F, Unit Sharing and Interactions, Amendment 23

6.3 Nuclear Utility Management and Resource Council (NUMARC) 87-00, Guidelines For and Technical Basis for NUMARC Initiatives for Addressing Station Blackout at Light Water Reactors

6.4 Generic Letter 2006-02, "Grid Reliability and the Impact on Plant risk and the Operability of Offsite Power"

6.5 NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," Section 8.4,III.3.O.iv

6.6 NUREG/CR-6890, "Reevaluation of Station Blackout Risks at Nuclear Power Plants - Analysis of Loss of Offsite Power Events: 1986-2004"

**ENCLOSURE 2**

**Browns Ferry Nuclear Plant**
**Units 1, 2, and 3**

**Technical Specifications (TS) Change TS-468 - Request for Extension to CT for TS 3.8.1 Required Action A.3, B.2, and B.5.**

**Proposed TS and TS Bases Changes (mark-ups)**

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ACTIONS

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| A. (continued) | A.2 Declare required feature(s) with no offsite power available inoperable when the redundant required feature(s) are inoperable.<br><br>AND | 24 hours from discovery of no offsite power to one shutdown board concurrent with inoperability of redundant required feature(s) |
| | A.3 Restore required offsite circuit to OPERABLE status. | 7 days<br><br>AND<br><br>21~~14~~ days from discovery of failure to meet LCO |
| B. One required Unit 1 and 2 DG inoperable. | B.1 Verify power availability from the offsite transmission network.<br><br>AND | 1 hour<br><br>AND<br><br>Once per 8 hours thereafter |

(continued)

ACTIONS

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| B. (continued) | B.2 Evaluate availability of both temporary diesel generators (TDGs). | 1 hour<br><br>AND<br><br>Once per 12 hours thereafter |
| | AND | |
| | B.~~3~~2 Declare required feature(s), supported by the inoperable Unit 1 and 2 DG, inoperable when the redundant required feature(s) are inoperable. | 4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s) |
| | AND | |
| | B.~~4~~3.1 Determine OPERABLE Unit 1 and 2 DG(s) are not inoperable due to common cause failure. | 24 hours |
| | OR | |
| | B.~~4~~3.2 Perform SR 3.8.1.1 for OPERABLE Unit 1 and 2 DG(s). | 24 hours |
| | AND | |

(continued)

ACTIONS

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| B. (continued) | B.54 Restore Unit 1 and 2 DG to OPERABLE status. | 7 days from discovery of unavailability of TDG(s)<br><br>AND<br><br>72 hours from discovery of Condition B entry ≥ 4 days concurrent with unavailability of TDG(s)<br><br>AND<br><br>14 days<br><br>AND<br><br>21~~14~~ days from discovery of failure to meet LCO |

(continued)

BASES

BACKGROUND (continued)

Non-Derated/Derated

a. 2600/2550 kW - continuous,

b. 2860/2800 kW - 0 to 2 hours (Short Time Steady State),

c. 2850 kW - 0 to 3 minutes (Cold Engine Instantaneous),

d. 3048 kW - > 3 minutes (Hot Engine Instantaneous).

The capability is provided to connect two temporary diesel generators (TDGs) to supply power to any of the eight 4.16 kV shutdown boards via the 4.16 kV tie-bus. The TDGs are commercial-grade and not designed to meet Class IE requirements. The TDGs are made available to support extended Completion Times in the event of an inoperable DG. The TDG is made available as a defense-in-depth alternate source of AC power to one ESF board to mitigate a station blackout event. The TDGs would remain disconnected from the Class 1E distribution system unless required during a station blackout event.

APPLICABLE SAFETY ANALYSES

The initial conditions of DBA and transient analyses in the FSAR, Chapter 6 (Ref. 4) and Chapter 14 (Ref. 5), assume ESF systems are OPERABLE. The AC electrical power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System (RCS), and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

and is based upon meeting the design basis of the unit. This

BASES

(continued)

BASES

ACTIONS

A.3 (continued)

The second Completion Time for Required Action A.3 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DG is inoperable, and that DG is subsequently returned OPERABLE, the LCO may already have been not met for up to 14~~7~~ days. This situation could lead to a total of 21~~4~~4 days, since initial failure to meet the LCO, to restore the offsite circuit. At this time, a DG could again become inoperable, the circuit restored OPERABLE, and an additional 14~~7~~ days (for a total of 35~~2~~1 days) allowed prior to complete restoration of the LCO. The 21~~4~~4 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 7 day and 21~~4~~4 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

As in Required Action A.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time the LCO was initially not met, instead of at the time that Condition A was entered.

(continued)

BASES

ACTIONS (continued)

B.1

To ensure a highly reliable power source remains with one Unit 1 and 2 DG inoperable, it is necessary to verify the availability of the required offsite circuits on a more frequent basis. This action ensures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. However, if an offsite circuit is not available, the offsite circuit is inoperable, and additional Conditions must then be entered.

B.2

In order to extend the Required Action B.5 Completion Time for an inoperable DG from 7 days to14 days inoperable, it is necessary to verify the availability of the TDGs on a more frequent basis. Since Required Action B.2 only specifies "evaluate," discovering one or both TDGs unavailable does not result in the Required Action being not met (i.e., the evaluation is performed). However, on discovery of an unavailable TDG, the Completion Time for Required Action B.5 starts the 7 day and/or 72 hour clock.

TDG availability requires that:

1) The combined loading capability has been demonstrated to exceed that of the inoperable DG. This demonstration must have been performed after being brought onsite and within the past 18 months. The Required Action evaluation is met with an administrative verification of this prior testing.

2) The corresponding control equipment and interconnecting cabling supplying power to the 4.16 kV shutdown board via the 4.16 kV tie-bus associated with the inoperable DG is confirmed available. The Required Action evaluation is met with (a) an administrative verification of prior testing and completion of preventative maintenance activities, and

(continued)

BASES

ACTIONS

B.2 (continued)

(b) general visual verification that connections and cabling from the TDGs to the Man-Way E are intact;

3) TDG fuel tank levels are verified locally to be ≥ 90%;

4) One fuel oil storage tank level is ≥ 60% and transfer capability is available; and

5) TDGs supporting system parameters for starting and operating are verified to be within required limits for functional availability (e.g., battery state of charge).

The TDGs are not used to extend the Completion Time for more than one inoperable DG at any one time.

B.~~3~~2

Required Action B.~~3~~2 is intended to provide assurance that a loss of offsite power, during the period that a Unit 1 and 2 DG is inoperable, does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related divisions (i.e., single division systems are not included). Redundant required features failures consist of inoperable features associated with a division redundant to the division that has an inoperable Unit 1 and 2 DG. For example, if DG A was inoperable and RHR pump D was inoperable for maintenance, then RHR pump A would have to be declared inoperable.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock."

(continued)

BASES

ACTIONS

B.3~~2~~ (continued)

In this Required Action the Completion Time only begins on discovery that both:

a. An inoperable Unit 1 and 2 DG exists; and

b. A required feature on, or supported by, the opposite or other division's 4.16 kV shutdown board is inoperable.

If, at any time during the existence of this Condition (one Unit 1 and 2 DG inoperable), a required feature in a redundant division subsequently becomes inoperable, this Completion Time begins to be tracked.

Discovering one Unit 1 and 2 DG inoperable coincident with one or more inoperable required support or supported features, or both, that are associated with the other division's OPERABLE DG[s] results in starting the Completion Time for the Required Action. Four hours from the discovery of these events existing concurrently is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

The remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection for the required feature's function may have been lost; however, function has not been lost. The 4 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 4 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and low probability of a DBA occurring during this period.

(continued)

BASES

ACTIONS (continued)

B.~~4~~3.1 and B.~~4~~3.2

Required Action B.~~4~~3.1 provides an allowance to avoid unnecessary testing of OPERABLE DGs. If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE Unit 1 and 2 DGs, SR 3.8.1.1 does not have to be performed. If the cause of inoperability exists on other Unit 1 and 2 DG(s), they are declared inoperable upon discovery, and Condition H of LCO 3.8.1 is entered. Once the failure is repaired, and the common cause failure no longer exists, Required Action B.~~3~~4.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining Unit 1 and 2 DG(s), performance of SR 3.8.1.1 suffices to provide assurance of continued OPERABILITY of those DGs.

In the event the inoperable DG is restored to OPERABLE status prior to completing either B.~~4~~3.1 or B.~~4~~3.2, the plant corrective action program will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition B.

According to Generic Letter 84-15 (Ref. 7), 24 hours is a reasonable time to confirm that the OPERABLE DGs are not affected by the same problem as the inoperable DG.

(continued)

BASES

ACTIONS (continued)

B.54

Based on the diversity of AC electrical power sources, and the remaining redundancy and reliability, operation may continue in Condition B for a period that should not exceed 14~~7~~ days if both TDGs are available. If one or both TDGs are or become unavailable with an inoperable DG, then action is required to restore both TDGs to available status or to restore the DG to OPERABLE status within 7 days from discovery of an unavailable TDG. However, if the TDG unavailability occurs sometime after 4 days of continuous DG inoperability, then the remaining time to restore both TDGs to available status or to restore the DG to OPERABLE status is limited to 72 hours

The 7 day and 72 hour Completion Times allow for an exception to the normal "time zero" for beginning the allowed outage time "clock." The 7 day Completion Time only begins on discovery that both:

a. An inoperable Unit 1 and 2 DG exists; and

b. One or both TDGs are unavailable.

The 72 hour Completion Time only begins on discovery that:

a. An inoperable Unit 1 and 2 DG exists for $\geq$ 4 days; and

b. One or both TDGs are unavailable.

Therefore, when one required DG is inoperable due to either preplanned maintenance (preventive or corrective) or unplanned corrective maintenance work, the Completion Time can be extended from 7 days to 14 days if both TDGs are verified available for backup operation.

In Condition B, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. The 14~~7~~ day Completion Time takes into account the capacity and capability of the remaining AC sources (including TDGs), reasonable time for repairs, and low probability of a DBA occurring during this period.

(continued)

BASES

ACTIONS (continued)

B.54

The fourth~~second~~ Completion Time for Required Action B.54 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an offsite circuit is inoperable and that circuit is subsequently restored OPERABLE, the LCO may already have been not met for up to 7 days. This situation could lead to a total of 21~~14~~ days, since initial failure to meet the LCO, to restore the DG. At this time, an offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional 7 days (for a total of 28~~21~~ days) allowed prior to complete restoration of the LCO. The 21~~14~~ day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 14~~7~~ day and 21~~14~~ day Completion Times means that both Completion Times apply simultaneously, and the more restrictive must be met.

As in Required Action B.3~~2~~, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time that the LCO was initially not met, instead of the time that Condition B was entered.

(continued)

ACTIONS

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| A. (continued) | A.2 Declare required feature(s) with no offsite power available inoperable when the redundant required feature(s) are inoperable.<br><br>AND | 24 hours from discovery of no offsite power to one shutdown board concurrent with inoperability of redundant required feature(s) |
| | A.3 Restore required offsite circuit to OPERABLE status. | 7 days<br><br>AND<br><br>2~~1~~14 days from discovery of failure to meet LCO |
| B. One required Unit 1 and 2 DG inoperable. | B.1 Verify power availability from the offsite transmission network.<br><br>AND | 1 hour<br><br>AND<br><br>Once per 8 hours thereafter |

(continued)

ACTIONS

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| B. (continued) | B.2 Evaluate availability of both temporary diesel generators (TDGs). | 1 hour<br>AND<br>Once per 12 hours thereafter |
| | AND | |
| | B.~~3~~2 Declare required feature(s), supported by the inoperable Unit 1 and 2 DG, inoperable when the redundant required feature(s) are inoperable. | 4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s) |
| | AND | |
| | B.~~4~~3.1 Determine OPERABLE Unit 1 and 2 DG(s) are not inoperable due to common cause failure. | 24 hours |
| | OR | |
| | B.~~4~~3.2 Perform SR 3.8.1.1 for OPERABLE Unit 1 and 2 DG(s). | 24 hours |
| | AND | |

(continued)

ACTIONS

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| B. (continued) | B.54 Restore Unit 1 and 2 DG to OPERABLE status. | 7 days from discovery of unavailability of TDG(s)<br><br>AND<br><br>72 hours from discovery of Condition B entry $\geq$ 4 days concurrent with unavailability of TDG(s)<br><br>AND<br><br>14 days<br><br>AND<br><br>21~~14~~ days from discovery of failure to meet LCO |

(continued)

BASES

BACKGROUND (continued)

Non-Derated/Derated

a. 2600/2550 kW - continuous,

b. 2860/2800 kW - 0 to 2 hours (Short Time Steady State),

c. 2850 kW - 0 to 3 minutes (Cold Engine Instantaneous),

d. 3048 kW - > 3 minutes (Hot Engine Instantaneous).

The capability is provided to connect two temporary diesel generators (TDGs) to supply power to any of the eight 4.16 kV shutdown boards via the 4.16 kV tie-bus. The TDGs are commercial-grade and not designed to meet Class IE requirements. The TDGs are made available to support extended Completion Times in the event of an inoperable DG. The TDG is made available as a defense-in-depth alternate source of AC power to one ESF board to mitigate a station blackout event. The TDGs would remain disconnected from the Class 1E distribution system unless required during a station blackout event.

APPLICABLE SAFETY ANALYSES

The initial conditions of DBA and transient analyses in the FSAR, Chapter 6 (Ref. 4) and Chapter 14 (Ref. 5), assume ESF systems are OPERABLE. The AC electrical power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System (RCS), and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

The OPERABILITY of the AC electrical power sources is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This

(continued)

BASES

ACTIONS

A.3 (continued)

The second Completion Time for Required Action A.3 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DG is inoperable, and that DG is subsequently returned OPERABLE, the LCO may already have been not met for up to 14~~7~~ days. This situation could lead to a total of 21~~4~~4 days, since initial failure to meet the LCO, to restore the offsite circuit. At this time, a DG could again become inoperable, the circuit restored OPERABLE, and an additional 14~~7~~ days (for a total of 35~~2~~1 days) allowed prior to complete restoration of the LCO. The 21~~4~~4 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 7 day and 21~~4~~4 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

As in Required Action A.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time the LCO was initially not met, instead of at the time that Condition A was entered.

(continued)

BASES

ACTIONS (continued)

B.1

To ensure a highly reliable power source remains with one Unit 1 and 2 DG inoperable, it is necessary to verify the availability of the required offsite circuits on a more frequent basis. This action ensures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. However, if an offsite circuit is not available, the offsite circuit is inoperable, and additional Conditions must then be entered.

B.2

In order to extend the Required Action B.5 Completion Time for an inoperable DG from 7 days to14 days inoperable, it is necessary to verify the availability of the TDGs on a more frequent basis. Since Required Action B.2 only specifies "evaluate," discovering one or both TDGs unavailable does not result in the Required Action being not met (i.e., the evaluation is performed). However, on discovery of an unavailable TDG, the Completion Time for Required Action B.5 starts the 7 day and/or 72 hour clock.

TDG availability requires that:

1) The combined loading capability has been demonstrated to exceed that of the inoperable DG. This demonstration must have been performed after being brought onsite and within the past 18 months. The Required Action evaluation is met with an administrative verification of this prior testing.

2) The corresponding control equipment and interconnecting cabling supplying power to the 4.16 kV shutdown board via the 4.16 kV tie-bus associated with the inoperable DG is confirmed available. The Required Action evaluation is met with (a) an administrative verification of prior testing and completion of preventative maintenance activities, and

(continued)

BASES

ACTIONS

B.2 (continued)

(b) general visual verification that connections and cabling from the TDGs to the Man-Way E are intact;

3) TDG fuel tank levels are verified locally to be ≥ 90%;

4) One fuel oil storage tank level is ≥ 60% and transfer capability is available; and

5) TDGs supporting system parameters for starting and operating are verified to be within required limits for functional availability (e.g., battery state of charge).

The TDGs are not used to extend the Completion Time for more than one inoperable DG at any one time.

B.3~~2~~

Required Action B.3~~2~~ is intended to provide assurance that a loss of offsite power, during the period that a Unit 1 and 2 DG is inoperable, does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related divisions (i.e., single division systems are not included). Redundant required features failures consist of inoperable features associated with a division redundant to the division that has an inoperable Unit 1 and 2 DG. For example, if DG A was inoperable and RHR pump D was inoperable for maintenance, then RHR pump A would have to be declared inoperable.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock."

(continued)

BASES

ACTIONS

B.3~~2~~ (continued)

In this Required Action the Completion Time only begins on discovery that both:

a. An inoperable Unit 1 and 2 DG exists; and

b. A required feature on, or supported by, the opposite or other division's 4.16 kV shutdown board is inoperable.

If, at any time during the existence of this Condition (one Unit 1 and 2 DG inoperable), a required feature in a redundant division subsequently becomes inoperable, this Completion Time begins to be tracked.

Discovering one Unit 1 and 2 DG inoperable coincident with one or more inoperable required support or supported features, or both, that are associated with the other division's OPERABLE DG[s] results in starting the Completion Time for the Required Action. Four hours from the discovery of these events existing concurrently is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

The remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection for the required feature's function may have been lost; however, function has not been lost. The 4 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 4 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and low probability of a DBA occurring during this period.

(continued)

BASES

ACTIONS (continued)

B.~~4~~3.1 and B.~~4~~3.2

Required Action B.~~4~~3.1 provides an allowance to avoid unnecessary testing of OPERABLE DGs. If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE Unit 1 and 2 DGs, SR 3.8.1.1 does not have to be performed. If the cause of inoperability exists on other Unit 1 and 2 DG(s), they are declared inoperable upon discovery, and Condition H of LCO 3.8.1 is entered. Once the failure is repaired, and the common cause failure no longer exists, Required Action B.~~4~~3.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining Unit 1 and 2 DG(s), performance of SR 3.8.1.1 suffices to provide assurance of continued OPERABILITY of those DGs.

In the event the inoperable DG is restored to OPERABLE status prior to completing either B.~~4~~3.1 or B.~~4~~3.2, the plant corrective action program will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition B.

According to Generic Letter 84-15 (Ref. 7), 24 hours is a reasonable time to confirm that the OPERABLE DGs are not affected by the same problem as the inoperable DG.

(continued)

BASES

ACTIONS (continued)

B.54

Based on the diversity of AC electrical power sources, and the remaining redundancy and reliability, operation may continue in Condition B for a period that should not exceed 14~~7~~ days if both TDGs are available. If one or both TDGs are or become unavailable with an inoperable DG, then action is required to restore both TDGs to available status or to restore the DG to OPERABLE status within 7 days from discovery of an unavailable TDG. However, if the TDG unavailability occurs sometime after 4 days of continuous DG inoperability, then the remaining time to restore both TDGs to available status or to restore the DG to OPERABLE status is limited to 72 hours

The 7 day and 72 hour Completion Times allow for an exception to the normal "time zero" for beginning the allowed outage time "clock." The 7 day Completion Time only begins on discovery that both:

a. An inoperable Unit 1 and 2 DG exists; and

b. One or both TDGs are unavailable.

The 72 hour Completion Time only begins on discovery that:

a. An inoperable Unit 1 and 2 DG exists for $\geq$ 4 days; and

b. One or both TDGs are unavailable.

Therefore, when one required DG is inoperable due to either preplanned maintenance (preventive or corrective) or unplanned corrective maintenance work, the Completion Time can be extended from 7 days to 14 days if both TDGs are verified available for backup operation.

In Condition B, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. The 14~~7~~ day Completion Time takes into account the capacity and capability of the remaining AC sources (including TDGs), reasonable time for repairs, and low probability of a DBA occurring during this period.

(continued)

BASES

ACTIONS (continued)

B.54

The fourth~~second~~ Completion Time for Required Action B.54 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an offsite circuit is inoperable and that circuit is subsequently restored OPERABLE, the LCO may already have been not met for up to 7 days. This situation could lead to a total of 21~~14~~ days, since initial failure to meet the LCO, to restore the DG. At this time, an offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional 7 days (for a total of 28~~21~~ days) allowed prior to complete restoration of the LCO. The 21~~14~~ day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 14~~7~~ day and 21~~14~~ day Completion Times means that both Completion Times apply simultaneously, and the more restrictive must be met.

As in Required Action B.3~~2~~, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time that the LCO was initially not met, instead of the time that Condition B was entered.

(continued)

ACTIONS

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| A. (continued) | A.2 Declare required feature(s) with no offsite power available inoperable when the redundant required feature(s) are inoperable.<br><br>AND | 24 hours from discovery of no offsite power to one shutdown board concurrent with inoperability of redundant required feature(s) |
| | A.3 Restore required offsite circuit to OPERABLE status. | 7 days<br><br>AND<br><br>2~~14~~ days from discovery of failure to meet LCO |
| B. One required Unit 3 DG inoperable. | B.1 Verify power availability from the offsite transmission network.<br><br>AND | 1 hour<br><br>AND<br><br>Once per 8 hours thereafter |

(continued)

ACTIONS

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| B. (continued) | B.2 Evaluate availability of both temporary diesel generators (TDGs). | 1 hour<br>AND<br>Once per 12 hours thereafter |
| | AND | |
| | B.~~3~~2 Declare required feature(s), supported by the inoperable Unit 3 DG, inoperable when the redundant required feature(s) are inoperable. | 4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s) |
| | AND | |
| | B.~~4~~3.1 Determine OPERABLE Unit 3 DG(s) are not inoperable due to common cause failure. | 24 hours |
| | OR | |
| | B.~~4~~3.2 Perform SR 3.8.1.1 for OPERABLE Unit 3 DG(s). | 24 hours |
| | AND | |

(continued)

ACTIONS

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| B. (continued) | B.54 Restore Unit 3 DG to OPERABLE status. | 7 days[(a)] from discovery of unavailability of TDG(s)<br><br>AND<br><br>72 hours from discovery of Condition B entry $\geq$ 4 days concurrent with unavailability of TDG(s)<br><br>AND<br><br>14 days<br><br>AND<br><br>2144 days from discovery of failure to meet LCO |

(continued)

~~(a) This 7-day Completion Time, which was entered on April 1, 2007, at 0815 hours, may be extended an additional 7 days to complete repair and testing of DG 3D. Unit 1 shall be maintained in a shutdown condition during this extended time interval.~~

BASES

BACKGROUND (continued)

elevation is less than 800 feet above sea level with maximum intake air temperatures of less than 115°F, the maximum instantaneous active power output does not require derating for temperature at BFN (Reference 12):

Non-Derated/Derated

a. 2600/2550 kW - continuous,

b. 2860/2800 kW - 0 to 2 hours (Short Time Steady State),

c. 2850 kW - 0 to 3 minutes (Cold Engine Instantaneous),

d. 3048 kW - > 3 minutes (Hot Engine Instantaneous).

The capability is provided to connect two temporary diesel generators (TDGs) to supply power to any of the eight 4.16 kV shutdown boards via the 4.16 kV tie-bus. The TDGs are commercial-grade and not designed to meet Class IE requirements. The TDGs are made available to support extended Completion Times in the event of an inoperable DG. The TDG is made available as a defense-in-depth alternate source of AC power to one ESF board to mitigate a station blackout event. The TDGs would remain disconnected from the Class 1E distribution system unless required during a station blackout event.

APPLICABLE SAFETY ANALYSES

The initial conditions of DBA and transient analyses in the FSAR, Chapter 6 (Ref. 4) and Chapter 14 (Ref. 5), assume ESF systems are OPERABLE. The AC electrical power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System (RCS), and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

BASES

(continued)

BASES

ACTIONS

A.3 (continued)

The second Completion Time for Required Action A.3 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DG is inoperable, and that DG is subsequently returned OPERABLE, the LCO may already have been not met for up to ~~14~~7 days. This situation could lead to a total of 21~~4~~4 days, since initial failure to meet the LCO, to restore the offsite circuit. At this time, a DG could again become inoperable, the circuit restored OPERABLE, and an additional ~~14~~7 days (for a total of 35~~2~~4 days) allowed prior to complete restoration of the LCO. The 21~~4~~4 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 7 day and 21~~4~~4 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

As in Required Action A.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time the LCO was initially not met, instead of at the time that Condition A was entered.

(continued)

BASES

ACTIONS (continued)

B.1

To ensure a highly reliable power source remains with one Unit 3 DG inoperable, it is necessary to verify the availability of the required offsite circuits on a more frequent basis. This action ensures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. However, if an offsite circuit is not available, the offsite circuit is inoperable, and additional Conditions must then be entered.

B.2

In order to extend the Required Action B.5 Completion Time for an inoperable DG from 7 days to14 days inoperable, it is necessary to verify the availability of the TDGs on a more frequent basis. Since Required Action B.2 only specifies "evaluate," discovering one or both TDGs unavailable does not result in the Required Action being not met (i.e., the evaluation is performed). However, on discovery of an unavailable TDG, the Completion Time for Required Action B.5 starts the 7 day and/or 72 hour clock.

TDG availability requires that:

1) The combined loading capability has been demonstrated to exceed that of the inoperable DG. This demonstration must have been performed after being brought onsite and within the past 18 months. The Required Action evaluation is met with an administrative verification of this prior testing.

2) The corresponding control equipment and interconnecting cabling supplying power to the 4.16 kV shutdown board via the 4.16 kV tie-bus associated with the inoperable DG is confirmed available. The Required Action evaluation is met with (a) an administrative verification of prior testing and completion of preventative maintenance activities, and

(continued)

BASES

ACTIONS

B.2 (continued)

(b) general visual verification that connections and cabling from the TDGs to the Man-Way E are intact;

3) TDG fuel tank levels are verified locally to be ≥ 90%;

4) One fuel oil storage tank level is ≥ 60% and transfer capability is available; and

5) TDGs supporting system parameters for starting and operating are verified to be within required limits for functional availability (e.g., battery state of charge).

The TDGs are not used to extend the Completion Time for more than one inoperable DG at any one time.

B.~~3~~2

Required Action B.~~3~~2 is intended to provide assurance that a loss of offsite power, during the period that a Unit 3 DG is inoperable, does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related divisions (i.e., single division systems are not included). Redundant required features failures consist of inoperable features associated with a division redundant to the division that has an inoperable Unit 3 DG. For example, if DG 3A was inoperable and RHR pump 3D was inoperable for maintenance, then RHR pump 3A would have to be declared inoperable.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock."

(continued)

BASES

ACTIONS

B.3~~2~~ (continued)

In this Required Action the Completion Time only begins on discovery that both:

a. An inoperable Unit 3 DG exists; and

b. A required feature on, or supported by, the opposite or other division's 4.16 kV shutdown board is inoperable.

If, at any time during the existence of this Condition (one Unit 3 DG inoperable), a required feature in a redundant division subsequently becomes inoperable, this Completion Time begins to be tracked.

Discovering one Unit 3 DG inoperable coincident with one or more inoperable required support or supported features, or both, that are associated with the other division's OPERABLE DG[s] results in starting the Completion Time for the Required Action. Four hours from the discovery of these events existing concurrently is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

The remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection for the required feature's function may have been lost; however, function has not been lost. The 4 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 4 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and low probability of a DBA occurring during this period.

(continued)

BASES

ACTIONS (continued)

B.~~4~~3.1 and B.~~4~~3.2

Required Action B.~~4~~3.1 provides an allowance to avoid unnecessary testing of OPERABLE DGs. If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE Unit 3 DGs, SR 3.8.1.1 does not have to be performed. If the cause of inoperability exists on other Unit 3 DG(s), they are declared inoperable upon discovery, and Condition H of LCO 3.8.1 is entered. Once the failure is repaired, and the common cause failure no longer exists, Required Action B.~~4~~3.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining Unit 3 DG(s), performance of SR 3.8.1.1 suffices to provide assurance of continued OPERABILITY of those DGs.

In the event the inoperable DG is restored to OPERABLE status prior to completing either B.~~4~~3.1 or B.~~4~~3.2, the plant corrective action program will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition B.

According to Generic Letter 84-15 (Ref. 7), 24 hours is a reasonable time to confirm that the OPERABLE DGs are not affected by the same problem as the inoperable DG.

(continued)

BASES

ACTIONS (continued)

B.54

Based on the diversity of AC electrical power sources, and the remaining redundancy and reliability, operation may continue in Condition B for a period that should not exceed 14~~7~~ days if both TDGs are available. If one or both TDGs are or become unavailable with an inoperable DG, then action is required to restore both TDGs to available status or to restore the DG to OPERABLE status within 7 days from discovery of an unavailable TDG. However, if the TDG unavailability occurs sometime after 4 days of continuous DG inoperability, then the remaining time to restore both TDGs to available status or to restore the DG to OPERABLE status is limited to 72 hours

The 7 day and 72 hour Completion Times allow for an exception to the normal "time zero" for beginning the allowed outage time "clock." The 7 day Completion Time only begins on discovery that both:

a. An inoperable Unit 1 and 2 DG exists; and

b. One or both TDGs are unavailable.

The 72 hour Completion Time only begins on discovery that:

a. An inoperable Unit 1 and 2 DG exists for $\geq$ 4 days; and

b. One or both TDGs are unavailable.

Therefore, when one required DG is inoperable due to either preplanned maintenance (preventive or corrective) or unplanned corrective maintenance work, the Completion Time can be extended from 7 days to 14 days if both TDGs are verified available for backup operation.

In Condition B, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. The 14~~7~~ day Completion Time takes into account the capacity and capability of the remaining AC sources (including TDGs), reasonable time for repairs, and low probability of a DBA occurring during this period.

(continued)

BASES

ACTIONS (continued)

B.54

The fourth~~second~~ Completion Time for Required Action B.54 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an offsite circuit is inoperable and that circuit is subsequently restored OPERABLE, the LCO may already have been not met for up to 7 days. This situation could lead to a total of ~~21~~14 days, since initial failure to meet the LCO, to restore the DG. At this time, an offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional 7 days (for a total of ~~28~~21 days) allowed prior to complete restoration of the LCO. The ~~21~~14 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the ~~14~~7 day and ~~21~~14 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive must be met.

As in Required Action B.~~3~~2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time that the LCO was initially not met, instead of the time that Condition B was entered.

(continued)

**ENCLOSURE 3**

**Browns Ferry Nuclear Plant**
**Units 1, 2, and 3**

**Technical Specifications (TS) Change TS-468 - Request for Extension to CT for TS 3.8.1 Required Action A.3, B.2, and B.5.**

**Proposed TS and TS Bases Changes (clean)**

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ACTIONS

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| A. (continued) | A.2 Declare required feature(s) with no offsite power available inoperable when the redundant required feature(s) are inoperable.<br><br>AND | 24 hours from discovery of no offsite power to one shutdown board concurrent with inoperability of redundant required feature(s) |
| | A.3 Restore required offsite circuit to OPERABLE status. | 7 days<br><br>AND<br><br>21 days from discovery of failure to meet LCO |
| B. One required Unit 1 and 2 DG inoperable. | B.1 Verify power availability from the offsite transmission network.<br><br>AND | 1 hour<br><br>AND<br><br>Once per 8 hours thereafter |

(continued)

ACTIONS

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| B. (continued) | B.2 Evaluate availability of both temporary diesel generators (TDGs). | 1 hour<br><br>AND<br><br>Once per 12 hours thereafter |
| | AND | |
| | B.3 Declare required feature(s), supported by the inoperable Unit 1 and 2 DG, inoperable when the redundant required feature(s) are inoperable. | 4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s) |
| | AND | |
| | B.4.1 Determine OPERABLE Unit 1 and 2 DG(s) are not inoperable due to common cause failure. | 24 hours |
| | OR | |
| | B.4.2 Perform SR 3.8.1.1 for OPERABLE Unit 1 and 2 DG(s). | 24 hours |
| | AND | |

(continued)

ACTIONS

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| B. (continued) | B.5 Restore Unit 1 and 2 DG to OPERABLE status. | 7 days from discovery of unavailability of TDG(s)<br><br>AND<br><br>72 hours from discovery of Condition B entry ≥ 4 days concurrent with unavailability of TDG(s)<br><br>AND<br><br>14 days<br><br>AND<br><br>21 days from discovery of failure to meet LCO |

(continued)

BASES

BACKGROUND (continued)

Non-Derated/Derated

a. 2600/2550 kW - continuous,

b. 2860/2800 kW - 0 to 2 hours (Short Time Steady State),

c. 2850 kW - 0 to 3 minutes (Cold Engine Instantaneous),

d. 3048 kW - > 3 minutes (Hot Engine Instantaneous).

The capability is provided to connect two temporary diesel generators (TDGs) to supply power to any of the eight 4.16 kV shutdown boards via the 4.16 kV tie-bus. The TDGs are commercial-grade and not designed to meet Class IE requirements. The TDGs are made available to support extended Completion Times in the event of an inoperable DG. The TDG is made available as a defense-in-depth alternate source of AC power to one ESF board to mitigate a station blackout event. The TDGs would remain disconnected from the Class 1E distribution system unless required during a station blackout event.

APPLICABLE SAFETY ANALYSES

The initial conditions of DBA and transient analyses in the FSAR, Chapter 6 (Ref. 4) and Chapter 14 (Ref. 5), assume ESF systems are OPERABLE. The AC electrical power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System (RCS), and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

and is based upon meeting the design basis of the unit. This

BASES

(continued)

BASES

ACTIONS

A.3 (continued)

The second Completion Time for Required Action A.3 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DG is inoperable, and that DG is subsequently returned OPERABLE, the LCO may already have been not met for up to 14 days. This situation could lead to a total of 21 days, since initial failure to meet the LCO, to restore the offsite circuit. At this time, a DG could again become inoperable, the circuit restored OPERABLE, and an additional 14 days (for a total of 35 days) allowed prior to complete restoration of the LCO. The 21 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 7 day and 21 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

As in Required Action A.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time the LCO was initially not met, instead of at the time that Condition A was entered.

(continued)

BASES

ACTIONS
(continued)

B.1

To ensure a highly reliable power source remains with one Unit 1 and 2 DG inoperable, it is necessary to verify the availability of the required offsite circuits on a more frequent basis. This action ensures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. However, if an offsite circuit is not available, the offsite circuit is inoperable, and additional Conditions must then be entered.

B.2

In order to extend the Required Action B.5 Completion Time for an inoperable DG from 7 days to14 days inoperable, it is necessary to verify the availability of the TDGs on a more frequent basis. Since Required Action B.2 only specifies "evaluate," discovering one or both TDGs unavailable does not result in the Required Action being not met (i.e., the evaluation is performed). However, on discovery of an unavailable TDG, the Completion Time for Required Action B.5 starts the 7 day and/or 72 hour clock.

TDG availability requires that:

1) The combined loading capability has been demonstrated to exceed that of the inoperable DG. This demonstration must have been performed after being brought onsite and within the past 18 months. The Required Action evaluation is met with an administrative verification of this prior testing.

2) The corresponding control equipment and interconnecting cabling supplying power to the 4.16 kV shutdown board via the 4.16 kV tie-bus associated with the inoperable DG is confirmed available. The Required Action evaluation is met with (a) an administrative verification of prior testing and completion of preventative maintenance activities, and

(continued)

BASES

ACTIONS

B.2 (continued)

(b) general visual verification that connections and cabling from the TDGs to the Man-Way E are intact;

3) TDG fuel tank levels are verified locally to be ≥ 90%;

4) One fuel oil storage tank level is ≥ 60% and transfer capability is available; and

5) TDGs supporting system parameters for starting and operating are verified to be within required limits for functional availability (e.g., battery state of charge).

The TDGs are not used to extend the Completion Time for more than one inoperable DG at any one time.

B.3

Required Action B.3 is intended to provide assurance that a loss of offsite power, during the period that a Unit 1 and 2 DG is inoperable, does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related divisions (i.e., single division systems are not included). Redundant required features failures consist of inoperable features associated with a division redundant to the division that has an inoperable Unit 1 and 2 DG. For example, if DG A was inoperable and RHR pump D was inoperable for maintenance, then RHR pump A would have to be declared inoperable.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock."

(continued)

BASES

ACTIONS

B.3 (continued)

In this Required Action the Completion Time only begins on discovery that both:

a. An inoperable Unit 1 and 2 DG exists; and

b. A required feature on, or supported by, the opposite or other division's 4.16 kV shutdown board is inoperable.

If, at any time during the existence of this Condition (one Unit 1 and 2 DG inoperable), a required feature in a redundant division subsequently becomes inoperable, this Completion Time begins to be tracked.

Discovering one Unit 1 and 2 DG inoperable coincident with one or more inoperable required support or supported features, or both, that are associated with the other division's OPERABLE DG[s] results in starting the Completion Time for the Required Action. Four hours from the discovery of these events existing concurrently is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

The remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection for the required feature's function may have been lost; however, function has not been lost. The 4 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 4 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and low probability of a DBA occurring during this period.

(continued)

BASES

ACTIONS (continued)

B.4.1 and B.4.2

Required Action B.4.1 provides an allowance to avoid unnecessary testing of OPERABLE DGs. If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE Unit 1 and 2 DGs, SR 3.8.1.1 does not have to be performed. If the cause of inoperability exists on other Unit 1 and 2 DG(s), they are declared inoperable upon discovery, and Condition H of LCO 3.8.1 is entered. Once the failure is repaired, and the common cause failure no longer exists, Required Action B.4.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining Unit 1 and 2 DG(s), performance of SR 3.8.1.1 suffices to provide assurance of continued OPERABILITY of those DGs.

In the event the inoperable DG is restored to OPERABLE status prior to completing either B.4.1 or B.4.2, the plant corrective action program will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition B.

According to Generic Letter 84-15 (Ref. 7), 24 hours is a reasonable time to confirm that the OPERABLE DGs are not affected by the same problem as the inoperable DG.

(continued)

BASES

ACTIONS (continued)

B.5

Based on the diversity of AC electrical power sources, and the remaining redundancy and reliability, operation may continue in Condition B for a period that should not exceed 14 days if both TDGs are available. If one or both TDGs are or become unavailable with an inoperable DG, then action is required to restore both TDGs to available status or to restore the DG to OPERABLE status within 7 days from discovery of an unavailable TDG. However, if the TDG unavailability occurs sometime after 4 days of continuous DG inoperability, then the remaining time to restore both TDGs to available status or to restore the DG to OPERABLE status is limited to 72 hours

The 7 day and 72 hour Completion Times allow for an exception to the normal "time zero" for beginning the allowed outage time "clock." The 7 day Completion Time only begins on discovery that both:

a. An inoperable Unit 1 and 2 DG exists; and

b. One or both TDGs are unavailable.

The 72 hour Completion Time only begins on discovery that:

a. An inoperable Unit 1 and 2 DG exists for $\geq$ 4 days; and

b. One or both TDGs are unavailable.

Therefore, when one required DG is inoperable due to either preplanned maintenance (preventive or corrective) or unplanned corrective maintenance work, the Completion Time can be extended from 7 days to 14 days if both TDGs are verified available for backup operation.

In Condition B, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. The 14 day Completion Time takes into account the capacity and capability of the remaining AC sources (including TDGs), reasonable time for repairs, and low probability of a DBA occurring during this period.

(continued)

BASES

ACTIONS (continued)

B.5

The fourth Completion Time for Required Action B.5 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an offsite circuit is inoperable and that circuit is subsequently restored OPERABLE, the LCO may already have been not met for up to 7 days. This situation could lead to a total of 21 days, since initial failure to meet the LCO, to restore the DG. At this time, an offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional 7 days (for a total of 28 days) allowed prior to complete restoration of the LCO. The 21 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 14 day and 21 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive must be met.

As in Required Action B.3, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time that the LCO was initially not met, instead of the time that Condition B was entered.

(continued)

ACTIONS

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| A. (continued) | A.2 Declare required feature(s) with no offsite power available inoperable when the redundant required feature(s) are inoperable.<br><br>AND | 24 hours from discovery of no offsite power to one shutdown board concurrent with inoperability of redundant required feature(s) |
| | A.3 Restore required offsite circuit to OPERABLE status. | 7 days<br><br>AND<br><br>21 days from discovery of failure to meet LCO |
| B. One required Unit 1 and 2 DG inoperable. | B.1 Verify power availability from the offsite transmission network.<br><br>AND | 1 hour<br><br>AND<br><br>Once per 8 hours thereafter |

(continued)

ACTIONS

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| B. (continued) | B.2 Evaluate availability of both temporary diesel generators (TDGs). | 1 hour<br><br>AND<br><br>Once per 12 hours thereafter |
| | AND | |
| | B.3 Declare required feature(s), supported by the inoperable Unit 1 and 2 DG, inoperable when the redundant required feature(s) are inoperable. | 4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s) |
| | AND | |
| | B.4.1 Determine OPERABLE Unit 1 and 2 DG(s) are not inoperable due to common cause failure. | 24 hours |
| | OR | |
| | B.4.2 Perform SR 3.8.1.1 for OPERABLE Unit 1 and 2 DG(s). | 24 hours |
| | AND | |

(continued)

ACTIONS

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| B. (continued) | B.5 Restore Unit 1 and 2 DG to OPERABLE status. | 7 days from discovery of unavailability of TDG(s)<br><br>AND<br><br>72 hours from discovery of Condition B entry $\geq$ 4 days concurrent with unavailability of TDG(s)<br><br>AND<br><br>14 days<br><br>AND<br><br>21 days from discovery of failure to meet LCO |

(continued)

BASES

BACKGROUND (continued)

Non-Derated/Derated

a. 2600/2550 kW - continuous,

b. 2860/2800 kW - 0 to 2 hours (Short Time Steady State),

c. 2850 kW - 0 to 3 minutes (Cold Engine Instantaneous),

d. 3048 kW - > 3 minutes (Hot Engine Instantaneous).

The capability is provided to connect two temporary diesel generators (TDGs) to supply power to any of the eight 4.16 kV shutdown boards via the 4.16 kV tie-bus. The TDGs are commercial-grade and not designed to meet Class IE requirements. The TDGs are made available to support extended Completion Times in the event of an inoperable DG. The TDG is made available as a defense-in-depth alternate source of AC power to one ESF board to mitigate a station blackout event. The TDGs would remain disconnected from the Class 1E distribution system unless required during a station blackout event.

APPLICABLE SAFETY ANALYSES

The initial conditions of DBA and transient analyses in the FSAR, Chapter 6 (Ref. 4) and Chapter 14 (Ref. 5), assume ESF systems are OPERABLE. The AC electrical power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System (RCS), and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

The OPERABILITY of the AC electrical power sources is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This

(continued)

BASES

ACTIONS

A.3 (continued)

The second Completion Time for Required Action A.3 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DG is inoperable, and that DG is subsequently returned OPERABLE, the LCO may already have been not met for up to 14 days. This situation could lead to a total of 21 days, since initial failure to meet the LCO, to restore the offsite circuit. At this time, a DG could again become inoperable, the circuit restored OPERABLE, and an additional 14 days (for a total of 35 days) allowed prior to complete restoration of the LCO. The 21 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 7 day and 21 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

As in Required Action A.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time the LCO was initially not met, instead of at the time that Condition A was entered.

(continued)

BASES

ACTIONS (continued)

B.1

To ensure a highly reliable power source remains with one Unit 1 and 2 DG inoperable, it is necessary to verify the availability of the required offsite circuits on a more frequent basis. This action ensures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. However, if an offsite circuit is not available, the offsite circuit is inoperable, and additional Conditions must then be entered.

B.2

In order to extend the Required Action B.5 Completion Time for an inoperable DG from 7 days to14 days inoperable, it is necessary to verify the availability of the TDGs on a more frequent basis. Since Required Action B.2 only specifies "evaluate," discovering one or both TDGs unavailable does not result in the Required Action being not met (i.e., the evaluation is performed). However, on discovery of an unavailable TDG, the Completion Time for Required Action B.5 starts the 7 day and/or 72 hour clock.

TDG availability requires that:

1) The combined loading capability has been demonstrated to exceed that of the inoperable DG. This demonstration must have been performed after being brought onsite and within the past 18 months. The Required Action evaluation is met with an administrative verification of this prior testing.

2) The corresponding control equipment and interconnecting cabling supplying power to the 4.16 kV shutdown board via the 4.16 kV tie-bus associated with the inoperable DG is confirmed available. The Required Action evaluation is met with (a) an administrative verification of prior testing and completion of preventative maintenance activities, and

(continued)

BASES

ACTIONS

B.2 (continued)

(b) general visual verification that connections and cabling from the TDGs to the Man-Way E are intact;

3) TDG fuel tank levels are verified locally to be $\geq$ 90%;

4) One fuel oil storage tank level is $\geq$ 60% and transfer capability is available; and

5) TDGs supporting system parameters for starting and operating are verified to be within required limits for functional availability (e.g., battery state of charge).

The TDGs are not used to extend the Completion Time for more than one inoperable DG at any one time.

B.3

Required Action B.3 is intended to provide assurance that a loss of offsite power, during the period that a Unit 1 and 2 DG is inoperable, does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related divisions (i.e., single division systems are not included). Redundant required features failures consist of inoperable features associated with a division redundant to the division that has an inoperable Unit 1 and 2 DG. For example, if DG A was inoperable and RHR pump D was inoperable for maintenance, then RHR pump A would have to be declared inoperable.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock."

(continued)

BASES

ACTIONS

B.3 (continued)

In this Required Action the Completion Time only begins on discovery that both:

a. An inoperable Unit 1 and 2 DG exists; and

b. A required feature on, or supported by, the opposite or other division's 4.16 kV shutdown board is inoperable.

If, at any time during the existence of this Condition (one Unit 1 and 2 DG inoperable), a required feature in a redundant division subsequently becomes inoperable, this Completion Time begins to be tracked.

Discovering one Unit 1 and 2 DG inoperable coincident with one or more inoperable required support or supported features, or both, that are associated with the other division's OPERABLE DG[s] results in starting the Completion Time for the Required Action. Four hours from the discovery of these events existing concurrently is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

The remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection for the required feature's function may have been lost; however, function has not been lost. The 4 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 4 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and low probability of a DBA occurring during this period.

(continued)

BASES

ACTIONS (continued)

B.4.1 and B.4.2

Required Action B.4.1 provides an allowance to avoid unnecessary testing of OPERABLE DGs. If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE Unit 1 and 2 DGs, SR 3.8.1.1 does not have to be performed. If the cause of inoperability exists on other Unit 1 and 2 DG(s), they are declared inoperable upon discovery, and Condition H of LCO 3.8.1 is entered. Once the failure is repaired, and the common cause failure no longer exists, Required Action B.4.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining Unit 1 and 2 DG(s), performance of SR 3.8.1.1 suffices to provide assurance of continued OPERABILITY of those DGs.

In the event the inoperable DG is restored to OPERABLE status prior to completing either B.4.1 or B.4.2, the plant corrective action program will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition B.

According to Generic Letter 84-15 (Ref. 7), 24 hours is a reasonable time to confirm that the OPERABLE DGs are not affected by the same problem as the inoperable DG.

(continued)

BASES

ACTIONS (continued)

B.5

Based on the diversity of AC electrical power sources, and the remaining redundancy and reliability, operation may continue in Condition B for a period that should not exceed 14 days if both TDGs are available. If one or both TDGs are or become unavailable with an inoperable DG, then action is required to restore both TDGs to available status or to restore the DG to OPERABLE status within 7 days from discovery of an unavailable TDG. However, if the TDG unavailability occurs sometime after 4 days of continuous DG inoperability, then the remaining time to restore both TDGs to available status or to restore the DG to OPERABLE status is limited to 72 hours

The 7 day and 72 hour Completion Times allow for an exception to the normal "time zero" for beginning the allowed outage time "clock." The 7 day Completion Time only begins on discovery that both:

a. An inoperable Unit 1 and 2 DG exists; and

b. One or both TDGs are unavailable.

The 72 hour Completion Time only begins on discovery that:

a. An inoperable Unit 1 and 2 DG exists for $\geq$ 4 days; and

b. One or both TDGs are unavailable.

Therefore, when one required DG is inoperable due to either preplanned maintenance (preventive or corrective) or unplanned corrective maintenance work, the Completion Time can be extended from 7 days to 14 days if both TDGs are verified available for backup operation.

In Condition B, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. The 14 day Completion Time takes into account the capacity and capability of the remaining AC sources (including TDGs), reasonable time for repairs, and low probability of a DBA occurring during this period.

(continued)

BASES

ACTIONS (continued)

B.5

The fourth Completion Time for Required Action B.5 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an offsite circuit is inoperable and that circuit is subsequently restored OPERABLE, the LCO may already have been not met for up to 7 days. This situation could lead to a total of 21 days, since initial failure to meet the LCO, to restore the DG. At this time, an offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional 7 days (for a total of28 days) allowed prior to complete restoration of the LCO. The 21 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 14 day and 21 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive must be met.

As in Required Action B.3, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time that the LCO was initially not met, instead of the time that Condition B was entered.

(continued)

ACTIONS

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| A. (continued) | A.2 Declare required feature(s) with no offsite power available inoperable when the redundant required feature(s) are inoperable.<br><br>AND | 24 hours from discovery of no offsite power to one shutdown board concurrent with inoperability of redundant required feature(s) |
| | A.3 Restore required offsite circuit to OPERABLE status. | 7 days<br><br>AND<br><br>21 days from discovery of failure to meet LCO |
| B. One required Unit 3 DG inoperable. | B.1 Verify power availability from the offsite transmission network.<br><br>AND | 1 hour<br><br>AND<br><br>Once per 8 hours thereafter |

(continued)

ACTIONS

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| B. (continued) | B.2 Evaluate availability of both temporary diesel generators (TDGs). | 1 hour<br><br>AND<br><br>Once per 12 hours thereafter |
| | AND | |
| | B.3 Declare required feature(s), supported by the inoperable Unit 3 DG, inoperable when the redundant required feature(s) are inoperable. | 4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s) |
| | AND | |
| | B.4.1 Determine OPERABLE Unit 3 DG(s) are not inoperable due to common cause failure. | 24 hours |
| | OR | |
| | B.4.2 Perform SR 3.8.1.1 for OPERABLE Unit 3 DG(s). | 24 hours |
| | AND | |

(continued)

ACTIONS

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| B. (continued) | B.5 Restore Unit 3 DG to OPERABLE status. | 7 days from discovery of unavailability of TDG(s)<br><br>AND<br><br>72 hours from discovery of Condition B entry $\geq$ 4 days concurrent with unavailability of TDG(s)<br><br>AND<br><br>14 days<br><br>AND<br><br>21 days from discovery of failure to meet LCO |

(continued)

BASES

BACKGROUND (continued)

elevation is less than 800 feet above sea level with maximum intake air temperatures of less than 115°F, the maximum instantaneous active power output does not require derating for temperature at BFN (Reference 12):

Non-Derated/Derated

a. 2600/2550 kW - continuous,

b. 2860/2800 kW - 0 to 2 hours (Short Time Steady State),

c. 2850 kW - 0 to 3 minutes (Cold Engine Instantaneous),

d. 3048 kW - > 3 minutes (Hot Engine Instantaneous).

The capability is provided to connect two temporary diesel generators (TDGs) to supply power to any of the eight 4.16 kV shutdown boards via the 4.16 kV tie-bus. The TDGs are commercial-grade and not designed to meet Class IE requirements. The TDGs are made available to support extended Completion Times in the event of an inoperable DG. The TDG is made available as a defense-in-depth alternate source of AC power to one ESF board to mitigate a station blackout event. The TDGs would remain disconnected from the Class 1E distribution system unless required during a station blackout event.

APPLICABLE SAFETY ANALYSES

The initial conditions of DBA and transient analyses in the FSAR, Chapter 6 (Ref. 4) and Chapter 14 (Ref. 5), assume ESF systems are OPERABLE. The AC electrical power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System (RCS), and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

BASES

(continued)

BASES

ACTIONS

A.3 (continued)

The second Completion Time for Required Action A.3 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DG is inoperable, and that DG is subsequently returned OPERABLE, the LCO may already have been not met for up to 14 days. This situation could lead to a total of 21 days, since initial failure to meet the LCO, to restore the offsite circuit. At this time, a DG could again become inoperable, the circuit restored OPERABLE, and an additional 14 days (for a total of 35 days) allowed prior to complete restoration of the LCO. The 21 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 7 day and 21 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

As in Required Action A.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time the LCO was initially not met, instead of at the time that Condition A was entered.

(continued)

BASES

ACTIONS (continued)

B.1

To ensure a highly reliable power source remains with one Unit 3 DG inoperable, it is necessary to verify the availability of the required offsite circuits on a more frequent basis. This action ensures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. However, if an offsite circuit is not available, the offsite circuit is inoperable, and additional Conditions must then be entered.

B.2

In order to extend the Required Action B.5 Completion Time for an inoperable DG from 7 days to14 days inoperable, it is necessary to verify the availability of the TDGs on a more frequent basis. Since Required Action B.2 only specifies "evaluate," discovering one or both TDGs unavailable does not result in the Required Action being not met (i.e., the evaluation is performed). However, on discovery of an unavailable TDG, the Completion Time for Required Action B.5 starts the 7 day and/or 72 hour clock.

TDG availability requires that:

1) The combined loading capability has been demonstrated to exceed that of the inoperable DG. This demonstration must have been performed after being brought onsite and within the past 18 months. The Required Action evaluation is met with an administrative verification of this prior testing.

2) The corresponding control equipment and interconnecting cabling supplying power to the 4.16 kV shutdown board via the 4.16 kV tie-bus associated with the inoperable DG is confirmed available. The Required Action evaluation is met with (a) an administrative verification of prior testing and completion of preventative maintenance activities, and

(continued)

BASES

ACTIONS

B.2 (continued)

(b) general visual verification that connections and cabling from the TDGs to the Man-Way E are intact;

3) TDG fuel tank levels are verified locally to be $\geq$ 90%;

4) One fuel oil storage tank level is $\geq$ 60% and transfer capability is available; and

5) TDGs supporting system parameters for starting and operating are verified to be within required limits for functional availability (e.g., battery state of charge).

The TDGs are not used to extend the Completion Time for more than one inoperable DG at any one time.

B.3

Required Action B.3 is intended to provide assurance that a loss of offsite power, during the period that a Unit 3 DG is inoperable, does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related divisions (i.e., single division systems are not included). Redundant required features failures consist of inoperable features associated with a division redundant to the division that has an inoperable Unit 3 DG. For example, if DG 3A was inoperable and RHR pump 3D was inoperable for maintenance, then RHR pump 3A would have to be declared inoperable.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock."

(continued)

BASES

ACTIONS

B.3 (continued)

In this Required Action the Completion Time only begins on discovery that both:

a. An inoperable Unit 3 DG exists; and

b. A required feature on, or supported by, the opposite or other division's 4.16 kV shutdown board is inoperable.

If, at any time during the existence of this Condition (one Unit 3 DG inoperable), a required feature in a redundant division subsequently becomes inoperable, this Completion Time begins to be tracked.

Discovering one Unit 3 DG inoperable coincident with one or more inoperable required support or supported features, or both, that are associated with the other division's OPERABLE DG[s] results in starting the Completion Time for the Required Action. Four hours from the discovery of these events existing concurrently is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

The remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection for the required feature's function may have been lost; however, function has not been lost. The 4 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 4 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and low probability of a DBA occurring during this period.

(continued)

BASES

ACTIONS (continued)

B.4.1 and B.4.2

Required Action B.4.1 provides an allowance to avoid unnecessary testing of OPERABLE DGs. If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE Unit 3 DGs, SR 3.8.1.1 does not have to be performed. If the cause of inoperability exists on other Unit 3 DG(s), they are declared inoperable upon discovery, and Condition H of LCO 3.8.1 is entered. Once the failure is repaired, and the common cause failure no longer exists, Required Action B.4.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining Unit 3 DG(s), performance of SR 3.8.1.1 suffices to provide assurance of continued OPERABILITY of those DGs.

In the event the inoperable DG is restored to OPERABLE status prior to completing either B.4.1 or B.4.2, the plant corrective action program will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition B.

According to Generic Letter 84-15 (Ref. 7), 24 hours is a reasonable time to confirm that the OPERABLE DGs are not affected by the same problem as the inoperable DG.

(continued)

BASES

ACTIONS (continued)

B.5

Based on the diversity of AC electrical power sources, and the remaining redundancy and reliability, operation may continue in Condition B for a period that should not exceed 14 days if both TDGs are available. If one or both TDGs are or become unavailable with an inoperable DG, then action is required to restore both TDGs to available status or to restore the DG to OPERABLE status within 7 days from discovery of an unavailable TDG. However, if the TDG unavailability occurs sometime after 4 days of continuous DG inoperability, then the remaining time to restore both TDGs to available status or to restore the DG to OPERABLE status is limited to 72 hours

The 7 day and 72 hour Completion Times allow for an exception to the normal "time zero" for beginning the allowed outage time "clock." The 7 day Completion Time only begins on discovery that both:

a. An inoperable Unit 1 and 2 DG exists; and

b. One or both TDGs are unavailable.

The 72 hour Completion Time only begins on discovery that:

a. An inoperable Unit 1 and 2 DG exists for $\geq$ 4 days; and

b. One or both TDGs are unavailable.

Therefore, when one required DG is inoperable due to either preplanned maintenance (preventive or corrective) or unplanned corrective maintenance work, the Completion Time can be extended from 7 days to 14 days if both TDGs are verified available for backup operation.

In Condition B, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. The 14 day Completion Time takes into account the capacity and capability of the remaining AC sources (including TDGs), reasonable time for repairs, and low probability of a DBA occurring during this period.

(continued)

BASES

ACTIONS (continued)

B.5

The fourth Completion Time for Required Action B.5 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an offsite circuit is inoperable and that circuit is subsequently restored OPERABLE, the LCO may already have been not met for up to 7 days. This situation could lead to a total of21 days, since initial failure to meet the LCO, to restore the DG. At this time, an offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional 7 days (for a total of 28 days) allowed prior to complete restoration of the LCO. The 21 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 14 day and 21 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive must be met.

As in Required Action B.3, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time that the LCO was initially not met, instead of the time that Condition B was entered.

(continued)

**ENCLOSURE 4**

**Browns Ferry Nuclear Plant**
**Units 1, 2, and 3**

**Technical Specifications (TS) Change TS-468 - Request for Extension to CT for TS 3.8.1 Required Action A.3, B.2, and B.5.**

**COMMITMENT LIST**

A. BFN "Engineering Procedure for TDGs Initial Acceptance Testing" will direct a load test of the TDGs initially after acceptance from the TDGs rental vendor and once per 18 months (while the TDGs are in TVA's custody) to ensure the TDGs' ability to accept, accelerate, and run assigned loads. The same procedure will direct routine preventative maintenance and a monthly unloaded test run, while the TDGs are on site, but only during periods when the TDGs are not credited as available during the extended CT. If the TDGs are needed again after being out of TVA control on site, TVA will re-perform the acceptance testing prior to entering the next planned DG inoperability that exceeds 7 days.

B. The TDGs will be protected, as a defense-in-depth, during the extended CT, and will be routinely monitored when they are not required to be available for the extended DG CT.

C. Required actions during a CT greater than 7 days will be to verify the TDGs fuel tanks are at least 90% full and to keep one FOST at least 60% full.

D. Licensed Operators and Assistant Unit Operators (AUO) will be appropriately trained on the purpose and use of the TDGs. A briefing/discussion of the revised TS 3.8.1 and putting TDGs in service will be completed prior to a planned DG inoperability that exceeds 7 days. Operating crews will be briefed on the DG work plan and procedural actions regarding LOOP and SBO.

E. Operators will monitor weather forecasts each shift. Weather conditions will be evaluated prior to intentionally entering the extended DG outage and will not be entered if official weather forecasts are predicting severe conditions (tornado or thunderstorm warnings). If severe weather or grid instability is expected after a DG outage begins, station managers will assess the conditions and determine the best course for returning the DG to an operable status.

F. The Transmission Operator (TRO) system dispatcher will be contacted once per day and BFN will inform the dispatcher of the DG status along with BFN offsite power needs. Prior to entering a planned DG inoperability that exceeds 7 days, BFN Operating Crew will hold discussions with the system load dispatcher to ensure no significant grid perturbations are expected during the planned DG inoperability that exceeds 7 days, and request that the system load dispatcher inform BFN if off site power conditions change during a planned DG inoperability that exceeds 7 days such that significant grid perturbations do occur or become expected.