December 30, 2003

Mr. James J. Sheppard
President and Chief Executive Officer
STP Nuclear Operating Company
South Texas Project Electric
Generating Station
P. O. Box 289
Wadsworth, TX 77483

SUBJECT: SOUTH TEXAS PROJECT, UNIT 2 - ISSUANCE OF AMENDMENT CONCERNING ONE-TIME ALLOWED OUTAGE TIME EXTENSION FOR NO. 22 STANDBY DIESEL GENERATOR (TAC NO. MC1643)

Dear Mr. Sheppard:

The Commission has issued the enclosed Amendment No. 149 to Facility Operating License No. NPF-80 for the South Texas Project, Unit 2. The amendment consists of changes to the Technical Specifications (TSs) in response to your application dated December 27, 2003, as supplemented by letter dated December 27 and two letters dated December 28, 2003. The license amendment is issued under the provisions of Section 50.91(a)(5) of Title 10 of the Code of Federal Regulations due to the time critical nature of the amendment.

The amendment revises TS 3.8.1, "AC Sources – Operating," to extend the allowed outage time for Unit 2 Standby Diesel Generator (SDG 22) from 21 days to 113 days as a one-time change for the purpose of making repairs to SDG 22.

A copy of our related Safety Evaluation is also enclosed. The Safety Evaluation describes the emergency circumstances under which the amendment was issued and the final determination of no significant hazards. The Notice of Issuance, addressing the final no significant hazards determination and opportunity for a hearing, associated with the emergency circumstances, will be included in the Commission's next biweekly *Federal Register* notice.

Sincerely,

/RA/
David Jaffe, Senior Project Manager, Section 1
Project Directorate IV
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket No. 50-499

Enclosures: 1. Amendment No. 149 to NPF-80
2. Safety Evaluation

cc w/encls: See next page

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ACCESSION NO: ML033640434 **NRR-058** ***See previous concurrence**

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Dated: December 30, 2003

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STP NUCLEAR OPERATING COMPANY

DOCKET NO. 50-499

SOUTH TEXAS PROJECT, UNIT 2

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 149
License No. NPF-80

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by STP Nuclear Operating Company* acting on behalf of itself and for Texas Genco, LP, the City Public Service Board of San Antonio (CPS), AEP Texas Central Company, and the City of Austin, Texas (COA) (the licensees), dated December 27, 2003, as supplemented by letter dated December 27 and two letters dated December 28, 2003, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, as amended, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this license amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

____

*STP Nuclear Operating Company is authorized to act for Texas Genco, LP, the City Public Service Board of San Antonio, AEP Texas Central Company, and the City of Austin, Texas, and has exclusive responsibility and control over the physical construction, operation, and maintenance of the facility.

2. Accordingly, (a) the licensee shall implement the compensatory measures described in its application dated December 27, 2003, as supplemented, and discussed in Sections 3.1.1.1 and 4.0 of the NRC staff's Safety Evaluation dated December 30, 2003, enclosed with this amendment; (b) the licensee may make changes to those compensatory measures without first obtaining a license amendment provided that the changes do not meet any of the criteria set forth in 10 CFR 50.59(c)(2); (c) the licensee shall obtain a license amendment pursuant to 10 CFR 50.90 before implementing any such change that does meet one of the criteria in 10 CFR 50.59(c)(2); and (d) the license is amended by changes to the Technical Specifications as indicated in the enclosure to this license amendment and paragraph 2.C.(2) of Facility Operating License No. NPF-80 is hereby amended to read as follows:

    (2) Technical Specifications

    The Technical Specifications contained in Appendix A, as revised through Amendment No. 149, and the Environmental Protection Plan contained in Appendix B, are hereby incorporated in the license. The STP Nuclear Operating Company shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. The license amendment is effective as of its date of issuance and shall be implemented immediately.

FOR THE NUCLEAR REGULATORY COMMISSION

/RA/
Robert A. Gramm, Chief, Section 1
Project Directorate IV
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Attachment: Changes to the Technical Specifications

Date of Issuance: December 30, 2003

ATTACHMENT TO LICENSE AMENDMENT NO. 149

FACILITY OPERATING LICENSE NO. NPF-80

DOCKET NO. 50-499

Replace the following pages of the Appendix A Technical Specifications with the attached revised pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

REMOVE	INSERT
3/4 8-7	3/4 8-7

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 149 TO

FACILITY OPERATING LICENSE NO. NPF-80

STP NUCLEAR OPERATING COMPANY, ET AL.

SOUTH TEXAS PROJECT, UNIT 2

DOCKET NO. 50-499

1.0 INTRODUCTION

By application dated December 27, 2003, as supplemented by letter dated December 27 and two letters dated December 28, 2003, STP Nuclear Operating Company (STPNOC or the licensee), requested changes to the Technical Specifications (TSs) for South Texas Project (STP), Unit 2.

The proposed changes would revise TS 3.8.1, "AC [alternating current] Sources – Operating," to extend the allowed outage time (AOT) for Unit 2 Standby Diesel Generator (SDG) 22 from 21 days to 113 days as a one-time change for the purpose of making repairs to SDG 22.

Specifically, for TS 3.8.1, ACTION Statements a, c, and f (which provide required restoration times for inoperable SDGs), the following note would be applied:

> (12) For the Unit 2 Train B standby diesel generator (SDG 22) failure of December 9, 2003, restore the inoperable standby diesel generator to OPERABLE status within 113 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

2.0 REGULATORY EVALUATION

The staff finds that the licensee in Section 5.2 of its December 27, 2003, submittal identified the applicable regulatory requirements. The regulatory guidance and requirements which the staff considered in reviewing the application included:

1. Regulatory Guide (RG) 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis,"

2. RG 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications."

3. RG 1.182, "Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants,"

4. Title 10, Code of Federal Regulations (10 CFR), Section 50.36, “Technical specifications,”

5. 10 CFR 50.65(a)(4), “Requirements for monitoring the effectiveness of maintenance at nuclear power plants,”

6. 10 CFR Part 50, Appendix A, General Design Criterion (GDC) 17, “Electric power systems,” and

7. 10 CFR Section 50.63, “Loss of all alternating current power.”

3.0 TECHNICAL EVALUATION

The staff has reviewed the licensee's regulatory and technical analyses in support of its proposed license amendment which is described in the licensee's submittal.

The licensee’s December 27, 2003, submittal, as supplemented, is risk-informed in that the licensee considered deterministic[1] and probabilistic[2] safety aspects. The NRC staff evaluated the deterministic and probabilistic assessments provided by the licensee.

3.1 Deterministic Evaluation

On October 31, 1996, the NRC staff issued License Amendment Nos. 85 and 72 to the Facility Operating Licenses for STP, Units 1 and 2. License Amendment Nos. 85 and 72 extended the AOT for a single SDG to 14 days. The NRC staff’s safety evaluation, issued in support of License Amendment Nos. 85 and 72, contained a deterministic evaluation to support the extension of the AOT; the evaluation considered the ability of the plant to cope with various accident scenarios with only two of the three SDGs operable, considering the effect of additional failures. The NRC staff, in Section 4.3.j of the safety evaluation concluded that:

> The staff has performed a deterministic evaluation of the licensee's proposed amendment, using engineering judgement to evaluate the risk associated with single train operation of STP, and determined that the proposed amendment is acceptable. Based on its review, the staff has concluded that the STP design has sufficient redundancy to allow the proposed AOT extensions and that the STP design will continue to meet the requirements of 10 CFR 50.46, "Acceptance criteria for emergency core cooling systems for light-water nuclear power reactors."

The NRC staff concludes that the October 31, 1996, safety evaluation and associated deterministic conclusions are applicable to the proposed 113 day AOT for SDG 22 since the

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[1] A deterministic analysis is an assessment of the availability of safety equipment necessary to ameliorate the consequences of design basis accidents.

[2] A probabilistic analysis is an assessment of the probability that given accident sequences will lead to core damage and/or a large early release of radioactivity.

deterministic evaluation is a function of the equipment configuration and the accident scenarios of interest, neither having changed (except for certain additional back-up electrical configurations.)   The NRC staff, however, has reevaluated the STP Unit 2 electrical design to assure that power to all critical safety equipment is maintained even in the event that off-site power is lost during the 92-day AOT extension for SDG 22.

3.1.1 STP Electrical Design

GDC 17, requires, in part, that nuclear power plants have onsite and offsite electric power systems to permit the functioning of structures, systems, and components that are important to safety. The onsite system is required to have sufficient independence, redundancy, and testability to perform its safety function, assuming a single failure. The offsite power system is required to be supplied by two physically independent circuits that are designed and located so as to minimize, to the extent practical, the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. In addition, this criterion requires provisions to minimize the probability of losing electric power from the remaining electric power supplies as a result of loss of power from the unit, the offsite transmission network, or the onsite power supplies.

The onsite power system for STP is provided with preferred power from the offsite system through two physically independent and redundant sources of power in accordance with 10 CFR Part 50, Appendix A, GDC 17. With regards to the safety-related (Class 1E) power supply configuration, normal power for the safety-related buses is supplied from either the unit auxiliary transformer through the 13.8 kV auxiliary buses or one preferred (offsite) power source from the 345 kV switchyard through the 13.8 kV standby buses. A second preferred (offsite) circuit is available for all standby buses from a second standby transformer. A third source of offsite power is available from the 138 kV system which feeds emergency bus 1L. Each 13.8 kV standby bus feeds a safety-related 4.16 kV bus through one of three auxiliary engineered safety feature (ESF) transformers (AUX ESFs). Emergency bus 1L is capable of feeding any of the AUX ESF transformers through disconnects into the primary of the transformer. Each AUX ESF transformer supplies power to an associated Class 1E 4.16 kV bus. For each safety-related bus normally fed by its associated ESF transformer, the capability exists for each bus to be supplied via the other preferred (offsite) source connection.

The onsite power system is divided into three load groups. Each load group consists of an arrangement of buses, transformers, switching equipment, and loads fed from a common power supply.

The onsite standby power system includes Class 1E AC and direct current (DC) power supply capability for equipment used to achieve and maintain a cold shutdown of the plant and to mitigate the consequences of a design basis accident (DBA). Two of the three load groups are needed to mitigate the DBA. Any one load group is independently capable of responding to a loss of offsite power (LOOP). With regards to the Class 1E AC power, each of the three Class 1E load groups, at the 4.16-kV bus level, is capable of being powered from an independent SDG (one per load group) which functions to provide power in the event of a loss of the preferred (offsite) power source.

The Commission's regulation at 10 CFR 50.63 requires the capability to withstand for a specified duration and recover from a station blackout, as defined in 10 CFR 50.2, "Definitions."

The specified station blackout duration shall be based upon four factors including the reliability of the onsite emergency power supplies. An alternate AC (AAC) power source constitutes an acceptable capability to withstand a station blackout. AAC source(s) serving a multiple unit site where onsite emergency AC sources are not shared between units is acceptable.

The STP updated final safety analysis report (UFSAR), Section 8.3.4, "Station Blackout," indicates that any one of the three independent SDGs may be credited as the AAC power source. The same section indicates that STP has also been classified as a four-hour coping plant with two independent SDGs. Therefore with SDG 22 inoperable, STP Unit 2 reverts back to its four-hour coping status.

3.1.1.1 Evaluation of STP Electrical Design

STP OPERABILITY requirements for the onsite and offsite AC sources during plant operation (MODES 1, 2, 3, and 4) are specified in TS 3.8.1. TS 3.8.1 includes AOTs that permit STP to continue to operate for 14 days with one SDG inoperable, 24 hours with two SDGs inoperable, and 2 hours with three SDGs inoperable. On December 23, 2003, the NRC staff issued License Amendment No. 148 which revised TS 3.8.1, to extend the allowed outage time for SDG 22 from 14 days to 21 days as a one-time change for the purpose of conducting additional inspections related to the failure of SDG 22.

The proposed change only applies to the one-time inoperability of SDG 22 due to the failure which occurred on December 9, 2003, and would permit continued operation of the plant for 113 days for the purpose of making repairs to SDG 22. Any condition associated with testing the remaining two SDGs that would require declaring the SDG being tested inoperable would require entering the Required Actions for two or more inoperable SDGs, as required by the current TSs.

Because the STP design has three Class 1E load groups, each powered by one of three independent SDGs, the plant retains a substantial capability to mitigate a DBA with an assumed single failure during the extended period that SDG 22 is inoperable. This is verified by Table 1, referenced in the licensee’s December 23, 2003, application for emergency amendment, as supplemented, which contains a short list (9 items) of functions affected with one inoperable SDG and an assumed single failure.

Also, as stated above, STP UFSAR Section 8.3.4, indicates that any one of the three independent SDGs may be credited as the AAC power source. The same section indicates that STP has also been classified as a four-hour coping plant with two independent SDGs. Therefore, with SDG 22 inoperable, STP Unit 2 reverts back to its four-hour coping status. The licensee stated in its December 23, 2003, application, as supplemented, that there has not been any modification to either STP unit that changes, affects, or shortens the four-hour coping period since the original Station Blackout submittal.

The licensee is also implementing compensatory measures during the extended AOT, in addition to those that are called for under STP’s existing Configuration Risk Management Program (CRMP). Following are the additional compensatory measures taken by STP:

- Notification of the transmission/distribution service providers (TDSP) of the condition and of the maintenance restrictions required for the STP switchyard.
- Hang extended AOT (EAOT) protected train signs.
- Planned maintenance on required systems, subsystems, trains, components, and devices that depend on the other trains of equipment during the EAOT SHALL NOT be performed.
- No planned maintenance that could result in an inoperable OPEN containment penetration.
- Containment purges shall be for pressure control only and for short duration.
- No planned maintenance on the Unit 2 Technical Support Center SDG.
- No planned maintenance on Load Center 2W.
- No planned maintenance on Motor Control Center 2G8.
- No planned maintenance on the Positive Displacement Charging Pump (PDP).
- No planned maintenance on the Emergency Transformer or the 138 kV Blessing to STP and Lane City to Bay City lines.
- No maintenance activities in the switchyard that could directly cause a LOOP event unless required to ensure the continued reliability and availability of the offsite power sources.
- No planned maintenance on the turbine-driven auxiliary feedwater pump.
- Attempt to verify that the station is not under hurricane, tornado, or flood watches or warnings. (Note: the licensee has indicated that no severe weather is currently forecast.)
- Attempt to verify with the TDSP that no adverse weather conditions exist in the areas of the offsite power supplies that challenge the stability of grid.
- Ensure the work schedule contains no planned maintenance on Switchgear 2L or 2K.

The NRC is confirming by license condition that the licensee will not change these compensatory measures except in accordance with an evaluation of the criteria in 10 CFR 50.59(c)(2).

With regard to severe weather, the amendment request states that severe weather events at the STP location are dominated by high winds caused by tornadoes and hurricanes. It states that tornadoes can occur at any time during a year, but typically occur most frequently between March and June. The hurricane season runs from May to early November.

Regarding icing, Section 8.2.1.1 of the STP UFSAR states that the structures for these circuits (transmission lines), as well as the 345 kV switchyard, are built to withstand hurricane force winds. In this area, the ice-loading condition on transmission lines is not considered significant since it is less than the hurricane wind loading on transmission or substation structures. In addition, the licensee has revised STP station procedures for responding to inclement weather to include guidance for coping with icing conditions that are affecting the offsite distribution system to adopt a strategy similar to the strategy currently in place to respond to hurricane force winds onsite. Specifically, in the event of a determination by the Duty Plant Manager after consultation with the TDSP that icing conditions in the area of STP may result in a loss of all power to the switchyard, STP will commence a shutdown of Unit 2 to MODE 3. The procedure also provides that one SDG be started and loaded to its ESF bus and that the ESF bus be subsequently removed from offsite power.

The licensee has developed procedural guidance to supply electrical power to an ESF bus in a unit that has lost all electrical power to its ESF busses from a functioning SDG in the opposite unit. This procedure will only be implemented when the failure of emergency power sources in a unit has occurred (including the temporary non-safety-related diesels described in the compensatory actions below) such that the remaining emergency power is judged to be inadequate for mitigation of the event and sufficient power is available in the opposite unit to meet its electrical power requirements.

The licensee committed in its December 27, 2003, letter, as supplemented, to install four vendor-supplied diesel generator sets that would be available for use by January 15, 2004, to provide temporary power to STP, if needed. The non-safety-related diesel generators (NDGs) will be capable of supplying power to an essential cooling water pump, an auxiliary feedwater pump, and required electrical auxiliary building ventilation to provide a backup power source for achieving safe shutdown. Each NDG will be capable of operating for 24 hours without refueling. Only three of the four NDGs are required to supply these loads. The NDGs will be connected to the STP non-safety emergency 13.8 kV electrical system.

The NDG capability will only be utilized when the failure of emergency power sources in Unit 2 has occurred such that the remaining emergency power is judged to be inadequate for mitigation of the event. The NDGs are started and switched to the non-safety emergency 13.8 kV electrical system locally. Operating procedures will be developed to line up and control the loading of the NDGs. The operating procedures will include appropriate precautions to prevent crosstie between the STP units.

The temporary equipment is not physically or electrically adjacent to any Class 1E or safety-related equipment. Therefore, the temporary equipment does not directly or indirectly affect the design function of safety-related equipment credited in the safety analyses.

The NDGs will be tested after installation and periodically thereafter. Vendor post-installation testing will include:

1) Verification that alarm functions, normal operating parameters, phase rotation, and the phasing between the NDGs is synchronous,

2) Load testing utilizing a load bank to ensure that the load demand on the NDG is distributed appropriately.

3) Verification that phasing between the NDGs and the emergency transformer is synchronous.

4) Verification that the starting batteries will perform their function.

The NDGs will be inspected weekly and operated monthly on a load bank to verify their availability.

3.1.1.2 Conclusions Regarding STP Electrical Design

The staff reviewed the licensee's submittal and found the proposed changes related to the ACTION statements in TS 3.8.1 to be acceptable based upon deterministic factors:

- The retention of substantial capability in the STP design to mitigate a DBA with an assumed single failure during the extended period that SDG-22 is inoperable.

- The four-hour station blackout coping capability of STP Unit 2 during the extended period that SDG 22 is inoperable.

- The additional compensatory measures taken by STP during the extended period that SDG 22 is inoperable, over and above those to be taken under the STP existing Configuration Risk Management Program.

- The commitment to commence a shutdown of Unit 2 to Mode 3 in the event of a determination by the Duty Plant Manager after consultation with the TDSP that icing conditions in the area of STP may result in a loss of all power to the STP switchyard.

- The ability to supply electrical power to an ESF bus in a unit that has lost all electrical power to its ESF busses from a functioning SDG in the opposite unit.

- The ability to supply electrical power to an ESF bus in Unit 2 from the NDGs when the failure of emergency power sources in Unit 2 has occurred, such that the remaining emergency power is judged to be inadequate for mitigation of the event. This capability will available by January 15, 2004.

3.2 Assessment of SDG 22 Failure

As indicated in the licensee's letter dated December 27, 2007, as supplemented, the licensee determined that the cause of the SDG 22 failure was microcracks created on the master connecting rod during manufacturing that propagated due to high cycle fatigue until the master connecting rod failed. The licensee subsequently inspected all STP Unit 1 and 2 SDGs. The results of the inspections indicated that no additional flaws, of the type which caused the failure of SDG 22, appear elsewhere in the SDGs, as documented in the licensee's letters dated December 23, 2003, for the Unit 1 SDGs (and SDG 22), and December 28, 2003 (the licensee's supplemental letter identified as NOC-AE-03001660, Supplement 2), for the remaining Unit 2 SDGs. This inspection result is significant because it provides assurance that the remaining, operable STP Unit 1 and 2 SDGs will not experience similar "common mode" failures during the 92-day SDG 22 AOT extension. The NRC staff's evaluation of the licensee's SDG inspections and SDG 22 failure assessment is contained herein.

3.2.1 SDG Inspections

In its December 27, 2003, application, the licensee identified the root cause of the December 9, 2003, failure of SDG 22, as "...microcracks created on the position 9 master connecting rod during manufacturing that propagated due to high cycle fatigue until the master connecting rod failed."

The NRC staff reviewed Ultrasonic Test (UT) procedure UTI-PA-002, Rev. 0, "Manual Ultrasonic Phased Array Examination on Diesel Generator Connecting Rod Assemblies," to determine if the procedure effectively detects cracks in the area of interest. The examination area is the thin region between the crankshaft bearing shell and the articulating rod pin bearing surface out to 1" past the oil passage. The technique uses pattern recognition from the geometric ultrasonic responses from a mockup that contains the existing oil groove and two Electric Discharge Machining (EDM) notches in the area where failure occurs. By letter dated December 27, 2003, the licensee provided supplemental information regarding the description of the notch sizes.

According to the licensee, the length of the notch is 0.428" on the journal surface, 0.161" deep, and 0.025" wide. The Figures show that the placement of the transducer is on the web of the actual failed connecting rod with an angle of incidence such that the area where cracking exists is ultrasonically examined. The placement of the notches is on a sound (UT) path greater than where the cracking exists and at an orientation similar to the cracking. The licensee demonstrated to onsite NRC staff personnel the ability to detect the notches with the described procedure.

The philosophy of Appendix VIII of Section XI of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code is to demonstrate the ability of the personnel, procedures and equipment to detect and size flaws in both welds and certain material product forms. Whereas all the requirements of Appendix VIII were not met, in this instance, the licensee demonstrated an ability to detect crack like flaws (EDM notches) at a metal path greater than where the cracking has occurred. The NRC staff concludes that the licensee provided reasonable assurance that they can detect cracks 0.161" deep, 0.428" long, and 0.025" wide, and that, in the absence of any detectable indications, no cracks greater than this size and length exist in the thin region between the crankshaft bearing shell and the articulating rod pin bearing surface.

The licensee has examined all of the master connecting rods of each Unit's SDGs using the UT procedure as discussed above, and detected no indications as stated in its application dated December 23, 2003, as supplemented, for the Unit 1 SDGs (and SDG 22), and December 28, 2003 (the licensee's letter identified as NOC-AE-03001660, Supplement 2), for the remaining Unit 2 SDGs. As a result, the NRC staff concludes that there is reasonable assurance that there exists no undetected flaws in the subject master connecting rods in the areas of interest, of a size equal to or greater than that which was demonstrated by the above referenced procedures.

3.2.2 SDG Connecting Rod Fatigue Failure Evaluation

The licensee postulates that microcracks on the surface of the master rod crankshaft bore occurred as a result of stress risers induced during manufacture (tool chatter), presence of an impurity, surface roughness, or irregularity in the metal. Machine problems such as a dull cutting tool, a small defect in the master connecting rod material, or contaminants can cause tool chatter. Once a microcrack develops and the connecting rod ligament undergoes alternating stresses, the microcrack slowly propagates through the master connecting rod until critical crack size is reached and failure occurs. Examination of the failed material indicated that the crack initiated on the master connecting rod in the ligament between the crankshaft bore and the articulated rod bushing bore. The crack propagated through the section thickness (approximately 1") and then propagated across the width of the bore. One side of the fracture essentially extended 100% across the width of the fracture face with only a small corner section showing overload. The other side of the fracture extended approximately 3.5" angled toward the articulated rod bushing surface, then failed due to overload. The width of the fatigue crack is 7" from a total of 9" of crack length. The licensee estimates that 65% of the fracture surface is high-cycle fatigue (HCF), 30% is overload, and 5% is impact damage after the failure. These estimates are based on an examination of the fractured surfaces.

The licensee stated that the metallurgical analysis of the SDG 22 failed connecting rod demonstrates that the failure mechanism was HCF. Metal fatigue generally progresses in three different stages: crack initiation, crack propagation, and section breakdown. In each stage there is some kind of repetitive, cyclic load below the normal strength limits of the material. In the case of the articulated rod connection to the main connecting rod, the cyclic loads that generate surface tensile stresses at the initiation site occur due to the inertial forces of the piston at the top of the exhaust stroke, or once for every two rotations of the crankshaft.

In its supplemental letter dated December 28, 2003 (Supplement 3), the licensee provided the length and depth (aspect ratio) of the critical crack which rapidly leads to catastrophic failure. In addition, the licensee provided the calculations which estimate how long it takes a minimal detectable crack that can be identified by UT examination to propagate to a critical crack. The calculations define the critical crack size for the present stress field is 7" long and 1" deep. At this size, the stress intensity K at the crack tip reaches the critical stress intensity value or the fracture toughness of the material in the given stress field. The licensee also provided the calculations and metallurgical examination results that estimate the number of diesel engine operating hours needed for crack initiation, crack growth to a detectable size crack, and crack growth to critical size. According to these calculation results, it would take between 10 to 20 million stress cycles or 550 to 1100 hours of operating time for a crack to initiate. The crack is estimated to grow to a minimum detectable size crack (0.16" deep) in 30 hours of operation. The detectability of such a crack based on UT examination is discussed in Section 3.2.1 of this safety evaluation. The operating time needed for the minimal detectable crack to grow to a critical crack size and failure according to the calculation is 970 operating hours. The crack growth estimate for this duration is based on the Paris Law equation.

The licensee stated that the fracture toughness properties for all emergency diesel generator connecting rods are nearly identical. Therefore the fatigue crack growth estimates would be applicable for all the engines. In support of this argument the licensee states the following.

> "The connecting rods for the Cooper KSV engines were produced to Cooper Energy Service Material Specification No. C-5B. The mechanical properties are those specified by ASTM [American Society of Testing and Materials]-A521 for Class CG forgings. The material specification allowed for alloys other than AISI [American Iron and Steel Institute]-41XX with specific chemistry limits on carbon and other elements. The #4

> connecting rod which failed in 1989 was AISI 1050 steel [ ], oil quenched and tempered to 197-241 Brinell, straightened and stress relieved at 1000°F. The #9 connecting rod was AISI 4140 steel [ ] similarly processed to meet the same Cooper specifications. Small changes in chemistry for similar steels do not affect fracture toughness significantly, provided the method of forming, heat treatment, and stress relief produce the same microstructure, yield strength and hardness, as is the case for these connecting rods. Therefore, fracture toughness properties for all connecting rods are expected to be nearly identical, since all the rods were produced to the same Cooper specifications for hardness and yield strength. Connecting rods used for the repair of SDG22 are "new" old stock manufactured to the same material specifications."

From the sub-critical fatigue crack to the final critical fast fracture stage, the crack growth is influenced by load redistribution. The forces imposed on the fracture surface drop off as the crack grows because there are alternate load paths to carry stress around the affected area. In other words, there is load redistribution as the compliance of the cracked region increases. Thus, the rate of crack growth decreases as the crack grows beyond a certain sub-critical size. The calculations conclude that it takes approximately 970 operating hours from the time that a crack can be detected by UT examination until failure. The licensee states that since the lowest operating hours on any engine is 1691 hours, sufficient operating time has elapsed such that any crack has had sufficient time to initiate and grow to a detectable size. Therefore, SDGs 11, 12, 13, 21, and 23 operate at stress levels below the endurance limit and are free from stress risers induced during manufacturing or by the presence of an impurity, surface roughness or irregularity in the metal. UT examinations recently conducted on these SDGs have confirmed that no detectable cracks exist.

The licensee has estimated that it takes 970 hours of operation for a detectable crack to grow to a critical crack size. During an emergency situation, the diesel engine would be required to continuously operate for up to 7 days or 168 hours. In its application dated December 27, 2003, the licensee committed to conduct UT examinations on all Unit 1 and Unit 2 SDGs at 500 operating hour intervals. The UT examination interval is based on subtracting 168 from 970 hours, indicating a maximum inspection interval of 802 hours. The licensee's commitment to perform UT inspections at 500 hour operating intervals is within the 802 hour maximum interval.

The NRC staff concludes that, since all connecting rods in SDGs 11, 12, 13, 21, and 23 have seen more than 1600 hours of operation, there is reasonable assurance that these connecting rods are operating below the endurance limit of the material, and common mode fatigue failure is not likely to occur above 1130 hours of operation (1100 hours for crack to develop + 30 hours to propagate to a detectible size). Based on its review of the information related to the connecting rod material properties, the NRC staff concludes that enough similarity in the fracture toughness properties validates the licensee's crack growth calculations and the applicability to all the engines. UT examinations that are to be conducted every 500 hours of operation on all Unit 1 and Unit 2 SDGs, will validate that no additional cracks in the master rod ligament between the crankshaft bore and articulated rod bushing bore should occur. The NRC staff concludes that the licensee's definition of critical crack size and estimation of time required for detectable crack growth to a critical size (970 operating hours) is acceptable because it is based on the standard definition of a critical crack size, which was corroborated by metallurgical examination of the fractured surfaces of the failed components. This licensee's calculation methodology based on the Paris Law equation is widely used for crack growth assessment and has been previously accepted by the staff for other similar applications.

3.3 Probabilistic Evaluation

3.3.1 Risk Assessment Evaluation

In evaluating the risk information submitted by the licensee, the NRC staff followed the three-tiered approach documented in RG 1.177.

Under the first tier, the NRC staff determines if the proposed change is consistent with the NRC's Safety Goal Policy Statement, as documented in RG 1.174. Specifically, the first tier objective is to ensure that the plant risk does not increase unacceptably during the period the equipment is taken out of service.

The second tier addresses the need to preclude potentially high-risk plant configurations that could result if additional equipment, not associated with the change, is taken out of service during the proposed 92-day additional AOT extension, for a total AOT of 113 days. The 113-day AOT includes the allowed 14-day AOT under the TS 3.8.1.1, followed by the 7-day extension that was provided in License Amendment No. 148 on December 23, 2003, and the proposed additional extension of 92 days.

The third tier addresses the establishment of a configuration risk management program for identifying risk-significant configurations resulting from maintenance or other operational activities, and taking appropriate compensatory measures to avoid such configurations.

3.3.2 Basis and Quality of Risk Assessment

The licensee used its Probabilistic Risk Assessment (PRA) model and appropriately conservative assumptions to assess the risk increase associated with operation at power for a period of 92 additional days without an operable SDG 22. The risk consideration included maintaining defense-in-depth and quantifying risk to determine the change in Core Damage Frequency (CDF) and Large Early Release Frequency (LERF) as a result of the proposed 92-day AOT extension for SDG 22. Also, the licensee is maintaining the continuous on-line risk management program to control the performance of other risk-significant tasks during the diesel maintenance with consideration of specific compensatory measures to minimize risk. During the previous 7-day extension, the licensee performed non-destructive examination (NDE) of the two remaining diesels, SDG 21 and SDG 23, to evaluate the potential for common mode failure. The dominant accident sequences contributing to the assessed risk increase include the occurrence of conditions due to the unavailability of and demand for the use of the SDG 22. During the 7-day extension provided by License Amendment No. 148, SDG 22 and SDG 21 were unavailable for 7.72 hrs, the duration of SDG 21 inspection, followed by an additional 7.42 hrs for the inspection of the SDG 23 with both SDG 22 and SDG 23 out-of-service. Currently, TS 3.8.1.1 allows two diesels to be out-of-service for 24 hours.

TS 3.8.1.1 requires three SDGs capable of supplying the onsite Class 1E power distribution subsystems for DBAs assuming single failure affecting any train. TS 3.8.1.1, Action b, states that with one SDG inoperable, the inoperable SDG must be returned to operable status within

14 days. Under the proposed amendment for a 92-day AOT extension, all DBA AC power requirements can be met with the operable SDGs without assuming a single failure.

The NRC staff evaluated the quality of the PRA models, major assumptions, and data used in the risk assessment. This evaluation compared the applicable findings from the NRC staff's review of the PRA with the NRC's Standardized Plant Analysis Risk Model (SPAR), Version 3.0.1, for the STP Unit 2 CDF and NRC Manual Chapter 0609, Appendix H for LERF, as well as findings from similar evaluations of similar plants. The NRC staff found them acceptable, based on the licensee's uncertainty analysis (error factor), which is discussed below.

3.3.2.1 System Alignment and Risk Modeling Assessment of the NDGs

The NDGs are assumed to fail with the same likelihood as the electric grid, and the NDGs are credited explicitly in the licensee's PRA for a duration from January 15, 2004 through March 31, 2004 during the proposed extension period. The NDGs will provide power to the Unit 2 "B" train components, replacing SDG 22, in the event of a LOOP. However, in the licensee's PRA model, the NDG is not credited for safety injection (SI) conditions for a loss-of-coolant accident, Steam Generator Tube Ruptures, and Steam Line Breaks. Although the NDGs are capable of providing power to Unit 2, trains "A" or "B," the licensee only credited power to train "B" in the risk model. In addition, the licensee did not credit the Unit 1/Unit 2 electrical cross-tie in the risk model.

Unlike the SDGs, the NDGs are not dependent upon the Essential Cooling Water System. The NDGs are credited for the LOOP initiating events, both transient-induced plant-centered LOOP scenarios and severe-weather and grid-centered LOOP scenarios. The NDGs are credited to support LOOP only and the automatic actuation of the NDGs in prescriptive timeframes are not required and modeled accordingly in the licensee PRA model. The failure rate and human errors associated with the NDGs are based on the plant experience and data as discussed in the following Section. A sensitivity study was performed by increasing the failure rate from 0.1 to 0.2.

3.3.2.2 Failure Rate and Operator Error

Failure rates for the NDGs and human errors associated with the NDGs were 0.1 each for the purpose of the analysis. The plant experience on NDGs for the balance-of-plant (BOP) and technical support center (TSC) were used for a 24-hour mission time. The failure rates for BOP and TSC diesels are 1.5E-02, 2.3E-03, and 2.7E-02 for failure in first hour, failure after first hour, and failure to start, respectively. The total failure rate of either unit is 9.2E-02.

The licensee performed a sensitivity analysis for the NDGs installed in the switchyard by varying the operator error probability from 0.1 to 0.25. In the sensitivity analyses of the NDG failure rate and human error, the incremental conditional core damage probability (ICCDP) for the NDGs with 0.2 of the failure rate and 0.25 for operator error increased almost linearly to 9.0E-07, still within the acceptable range.

3.3.3 Risk Impact of the Proposed Change (Tier 1)

An acceptable approach to risk-informed decisionmaking is to show that the proposed change to the design basis meets several key principles. One of these principles is to show that the proposed change results in a small but acceptable increase in risk in terms of CDF and LERF, and is consistent with the NRC’s Safety Goal Policy Statement. Acceptance guidelines for meeting this principle are presented in RG 1.174. The licensee used its PRA model of STP Unit 2 to calculate risk increases due to the previous AOT extension of 7 days, during which SDG 21 and SDG 22 were unavailable for 7.72 hrs, and SDG 22 and SDG 23 for 7.42 hrs. Both the ICCDP and the incremental conditional large early release probability (ICLERP) were assessed. These quantities are a measure of the increase in probability of core damage and large early release, respectively, during a single outage that would last for the entire duration allowed by the proposed change. Based on the one-time extension of 7 days from December 23, 2003 to December 30, 2003, the incremental changes in CDF and LERF are summarized in the following table:

TABLE 1
7-Day SDG 22 AOT Extension

		Baseline CDF	Incremental Change in CDP	Baseline LERF	Incremental Change in LERF
Prior to AOT Extension		9.1E-06/yr		5.2-07/yr	
ICCDP with 7-day AOT Extension	7.72 hrs without SDGs 21 and 22		4.2E-07		3.5E-08
	7.42 hrs without SDGs 22 and 23		3.9E-07		3.1E-08
	152.86 hrs without SDG 22 only		3.8E-07		2.8E-08
	7-day Total		1.2E-06		9.4E-08
Total annualized increase in CDF during 7-day AOT extension			1.2E-06/yr		9.4E-08/yr
New Baseline CDF after 7 day AOT extension based on annualized ICCDP		1.03E-05/yr		6.3E-07/yr	

Due to these increases of the annualized CDF and LERF, the baseline values are increased from 9.1E-06/yr to 1.03E-05/yr for CDF, and from 5.2E-7/yr to 6.34E-07/yr for LERF.

Under the proposed one-time AOT extension of 92 days, the licensee will ensure that the NDGs will be operational by no later than January 15, 2004. The NDGs will provide power to Unit 2 “B” train components, in place of the damaged SDG 22, and will be available until SDG 22 is operable. Summarizing the different plant configurations during the 92-day AOT extension for SDG 22:

1. The NDE of the SDGs indicated that the failure of the SDG 22 was not caused by a new common mode failure mechanism, not incorporated in the current PRA. The annualized CDF and LERF increases due to the 7-day plant configurations, the baseline CDF and

LERF were increased to a new baseline value of 1.03E-05/yr and 6.34E-07/yr respectively.

2. The proposed second extension request covers 92 days from December 30, 2003, to March 31, 2004. During the first 17 days (from December 30, 2003, through January 15, 2004), the plant will operate with only two SDGs for Unit 2.

3. The NDGs are being installed and expected to be operational by no later than January 15, 2004. The NDGs will be installed in place of SDG 22 for the "B" train, and the licensee is taking this credit for a period of 75 days. The NDGs will provide emergency power for LOOP (for internal and external events), but will not provide any support for SI.

The following table summarizes CDF and LERF contribution by various configurations during the proposed 92-day AOT extension:

TABLE 2
92-Day SDG 22 AOT Extension

		Total CDF	ICCDP	Total LERF	ICLERP
Prior to 7-day extension		9.1E-06/yr		5.2E-07/yr	
During 7-day Extension			1.2E-06		9.4E-08
After 7-day Extension		1.03E-05/yr		6.14E-07/yr	
92-day with NDG Credit	First 17 days without NDG (12/30/2003 – 1/15/2004)		9.6E-07		7.1E-07
	Next 75 days with NDG (01/15/2004 – 3/31/2004)		2.8E-07		1.5E-08
	Total for 92 days (12/30/2003 -03/31/2004) **(RG 1.174)**	1.27E-5/yr	2.4E-06 **(<1.0E-05)**	7.94E-07/yr	1.8E-07 **(<1.0E-06)**
92 days without NDG Credit	Total 92 days without NDG (12/30/2003 – 03/31/2004) **(RG 1.174)**	1.77E-05/yr	7.4E-06 **(<1.0E-05)**	1.13E-06/yr	5.2E-07 **(<1.0E-06)**

The acceptance guidelines in RG 1.177 and RG 1.174 are for permanent changes, and the proposed extension is a one-time extension. The acceptance guidance criteria in RG 1.177 for annualized CDF increase of 5.0E-07/yr and 5.0E-08 for annualized LERF, respectively, are for permanent changes and are not directly applicable for a one-time change. For a one-time change, the acceptance guidance criteria and threshold values are generally less restrictive and higher than that for a permanent change by as much as an order of magnitude.

For a 92-day AOT extension without NDGs being credited, the ICCDP value of 7.4E-06 (or annualized CDF increase of 7.4E-06/yr) will meet the RG 1.174 guideline value of 1.0E-05 (or annualized CDF increase of 1.0E-05/yr). However, considering the error factor of 2, the annualized CDF increase of 7.4E-06/yr does not provide enough statistical margin.

For a 92-day AOT extension with credit for the NDGs, the annualized increase in CDF is 2.4E-06/yr and LERF is 1.8E-07/yr, which are within the RG 1.174 acceptable values with enough statistical margin for temporary increases, and will increase the baseline CDF and LERF by the respective annualized values for one-year period. Therefore, in accordance with the RG 1.174 guidelines, the licensee's proposed change to allow for a one-time extension of the AOT for an additional 92 days for SDG 22 (with credit for the NDGs) results in an acceptable increase in risk which is small and consistent with the NRC's Safety Goal Policy Statement.

Parametric evaluation of the uncertainty by the licensee indicated that the error factor, a ratio of 95 percentile (1.7E-5)-to-50 percentile (median), was approximately 2, with the median value of 8.1E-06/yr. Confirmatory calculations of ICCDP and annualized CDF increase using NRC's SPAR, version 3.01, were well within the range. For a large dry containment, the risk impact on LERF is mostly because of a containment bypass and steam generator tube rupture sequences, according to the Significance Determination Process analysis (Appendix H in NRC Manual Chapter 0609), and therefore, acceptable.

Because of the severity of the current failure, as well as a similar failure of the same diesel experienced in 1989, other potential common causes of failure that are either not recognized or not incorporated in the licensee's PRA model were evaluated. According to the NDE examination of SDG 21 and SDG 23, as well as evaluation of NDE results of other diesels, the licensee concluded that the root causes and the initiation mechanism of the current event are not initiated by new unevaluated common mode failures. The staff found that there is a small probability of potential common mode failure due to excess fatigue, and that initiation of the crack(s) will be on a site with defects on materials. The NDE examination was based on the tests conducted on unit 2 diesels, during the 7-day extension period.

External events in the licensee's PRA model account for approximately 20% of the total CDF with severe weather and flooding as major contributors, leading to LOOP sequences. The LOOP events due to severe weather are dominated by high winds of tornadoes and hurricanes. The potential for severe weather was reviewed based the information provided by the licensee and data available from the National Oceanographic and Atmospheric Administration (NOAA). According to data reported by the National Climate Data Center (NCDC), the STP site (Matagorda County in Texas) experienced a total of 8 high wind or hail-related weather events during a period from January 1, 1950 to July 31, 2003. Based on the information available from the NCDC (www.ncdc.noaa.gov), this review was limited to the additional 92-day AOT from December 30, 2003 to March 31, 2004. In the NCDC report for the time series of probability for tornado cycle, the cumulative probability of severe weather during last 30 days (December) and first 90 days (January, February, and March) of a year is less than 5%, and major bad weather occurs during March. In fact, over 3% of bad weather occurs during March. This statistical data covers a period of 20 years since 1980. Peak seasons of the tornadoes and hurricanes are March through June and May through November, respectively.

The likelihood of having either tornadoes or hurricanes in December through March for the duration of the proposed SDG 22 AOT extension is small. STP has not experienced any LOOP caused by icing conditions or ice storms during the entire operating period since March 1987, although both units were shut down during a 1989 ice storm. The likelihood of having an ice storm during the 92-day SDG 22 AOT extension period that would affect the offsite power would be less than one-in-ten-thousand, and the likelihood of core damage as a result of LOOP would be small.

3.3.4 Avoidance of High Risk Plant Configurations (Tier 2)

The licensee's PRA identified and estimated major risk contributors of plant configurations, contributing event sequences, and associated cutsets. Potential major risk contributors include plant equipment failures, human errors and common cause failures. Insights from the risk assessment would be used in identifying and monitoring the plant configurations or conditions that may lead to significant risk increases during implementation of the proposed 92-day SDG 22 AOT extension. The NRC staff finds that the proposed precautions, as well as the proposed compensatory measures listed in Section 3.1.1.1, are adequate for preventing plant configurations or conditions that may increase risk significantly. However, the proposed 92-day extension, during which there is a reasonable likelihood of experiencing predictable and unplanned plant evolutions may result in plant configurations with small risk contributions.

3.3.5 Risk-Informed Configuration Risk Management (Tier 3)

The intent of risk-informed configuration risk management is to ensure that plant safety is maintained and monitored during an extended outage. A formal commitment to maintain a configuration risk management program is necessary on the part of a licensee prior to implementation of a risk-informed TS whenever such TS Limiting Condition for Operation (LCO) is entered and risk-significant components are taken out of service. The licensee has programs in place for STP Unit 2 to comply with 10 CFR 50.65(a)(4) to assess and manage risk from proposed maintenance activities. These programs can support the licensee's decision-making regarding the appropriate actions to control risk whenever a risk-informed TS LCO is entered.

The licensee is committed to comply with the risk action thresholds specified in the Section 11.3.7.2 of NUMARC 93-01 in conjunction with the guidelines provided in RG 1.182 as standards for implementation of the maintenance rule, 10 CFR 50.65. With the ICCDP of 2.4E-06 (with NDGs credited), the licensee addressed the non-quantifiable factors listed in Section 4.4, Attachment 1 of the December 28, 2003, letter and will establish risk management actions accordingly. The licensee will adhere to the station configuration risk management program specified in procedure OPGP03-ZA-0091, Revision 5, December 31, 2002.

3.3.6 Conclusions Regarding Probabilistic Evaluation

The NRC staff has concluded that the proposed 92-day one-time extension of the AOT for SDG 22 is acceptable from a PRA perspective. This conclusion is based, in part, on:

- reliability of offsite power
- operability of SDG 21 and SDG 23
- NDGs operable by January 15, 2004, credited to provide back-up power to Unit 2 train "B"
- low likelihood of SDG common-mode failure
- low likelihood of failure of credited power sources

In addition, the licensee will take compensatory measures limiting activities that could result in a plant configuration with the potential for a transient or to adversely impact the availability of onsite or offsite power supplies. The licensee will establish a plant configuration management program, and continue to monitor plant configurations to avoid high risk configurations. Therefore, the NRC staff finds that the licensee's PRA of the 92-day AOT extension for SDG 22 is acceptable.

3.4 Conclusions Regarding Change to TS 3.8.1

The NRC staff has evaluated the licensee's proposed change to TS 3.8.1 and concludes that the licensee's proposed 113-day AOT for SDG 22 meets the NRC staff's deterministic and probabilistic standards for such AOT extensions. Accordingly, it is acceptable to change TS 3.8.1, ACTION Statements a, c, and f (which provide required restoration times for inoperable SDGs), by applying the following note:

(12) For the Unit 2 Train B standby diesel generator (SDG 22) failure of December 9, 2003, restore the inoperable standby diesel generator to OPERABLE status within 113 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

4.0 REGULATORY COMMITMENTS

During the 92 additional days of the SDG 22 AOT extension, the licensee has made the following commitments (as stated):

1. STPNOC plans to perform phased array ultrasonic examination of all master connecting rods in the three Unit 1 SDGs and in SDG 22 by December 22, 2003, contingent upon their availability for examination. **(Complete)**

2. STPNOC plans to perform phased array ultrasonic examination of all master connecting rods in SDG 21 and SDG 23 following the SDG 22 return to service. **(Complete)**

3. NDE will be performed on any master connecting rods before they are installed in SDG 22.

4. STPNOC will perform a similar phased array ultrasonic examination at appropriate intervals (based on accumulated run time between examinations) during planned diesel outages until the diesel engines accumulate sufficient run time that these inspections are no longer necessary. These inspections will be conducted at the 5-year overhaul of each engine (i.e., approximately every 500 hours of operation) and on SDG 22 after the engine accumulates 500 hours run time after the rebuild.

5. If at any time STP discovers, or becomes aware that they may not be able to complete repairs and return SDG 22 to operability within the 61-day AOT, then STP will take the following actions: **(Complete)**

    a) STP will inform the NRC in a timely manner.

    b) STP will evaluate the condition, its impact on the repair schedule, and the potential to pursue a request for an extension beyond the approved 61-day AOT. If considered appropriate, STP will apply for relief from this license condition.

    c) If the evaluation determines that it is not appropriate to pursue a supplemental license amendment request, or if the NRC Staff indicates that it will not approve such a request, STP will implement the shutdown requirements of TS 3.8.1.1.

6. STP will revise station procedures for responding to inclement weather to include guidance for coping with icing conditions that are affecting the offsite distribution system to adopt a similar strategy to the strategy currently in place to respond to hurricane force winds onsite. Specifically, in the event of a determination by the Duty Plant Manager after consultation with the TDSP that icing conditions in the area of STP may result in a loss of all power to the switchyard, STP will commence a shutdown of Unit 2 to Mode 3. The procedure will also require that one Standby Diesel be started and loaded to its ESF bus and that the ESF bus be subsequently removed from offsite power. These procedure revisions will be completed by December 23, 2003. **(Complete)**

7. STP is developing procedural guidance to supply electrical power to an ESF bus in a unit that has lost all electrical power to its ESF busses from a functioning Emergency Diesel in the opposite unit. This procedure will only be implemented when the failure of emergency power sources in a unit has occurred (including the temporary non-safety-related diesels described in the compensatory actions) such that the remaining emergency power is judged to be inadequate for mitigation of the event and sufficient power is available in the opposite unit to meet its electrical power requirements. This procedure will be approved by December 23, 2003. **(Complete)**

8. STP will monitor changes in planned risk levels using the CRMP. During the extended AOT, the calculated average CDF levels will be updated in the event unplanned maintenance is required on equipment within the scope of the CRMP. Risk levels will be monitored throughout the SDG 22 outage and STP will comply with the risk threshold actions required by the CRMP. In addition, STPNOC will keep the NRC Resident Inspector apprised of deviations from the expected risk profile for the duration of the SDG 22 repair.

9. The temporary non-safety-related diesel capability described in [supplemental] letter dated December 20, 2003 (NOC-AE-03001653), will be available for use by January 15, 2004.

10. To provide further confirmation that there is no potential for common mode failure, STPNOC will apply the 7 day AOT extension proposed in Reference 4 and approved by Reference 5 of the cover letter [of the December 27, 2003, application] to inspect the connecting rods on the other two Unit 2 SDGs and apprise the NRC of the results of the inspections. This will fulfill commitment number 2 in Reference 3 [of the December 27, 2003 application]. **(Complete)**

The above compensatory measures have been entered as regulatory commitments in the licensee's Commitment Management System, which complies with Nuclear Energy Institute's Document 99-04, Revision 0, "Guidelines for Managing NRC Commitment Changes." The NRC staff has reviewed the compensatory measures and how they will be controlled, and finds that the licensee's commitments provide adequate assurance that safe plant operation will not be affected by the extended AOT for SDG 22.

On December 30, 2003, the NRC staff conferred with Mr. T. Jordan, Vice President of Engineering and Technical Services, representing the licensee. Mr. Jordan acceded to the NRC staff's imposition of a license condition regarding the control of the licensee's commitments and compensatory measures described in Sections 3.1.1.1 and 4.0 of this safety evaluation.

5.0 EMERGENCY CIRCUMSTANCES

The NRC's regulations at 10 CFR 50.91 contain provisions for issuance of an amendment where the Commission finds that an emergency situation exists in that failure to act in a timely way would result in shutdown of a nuclear power plant. In such a situation, the NRC may issue a license amendment involving no significant hazards consideration without prior notice and opportunity for a hearing or for public comment. In such a situation, the Commission will not publish a notice of proposed determination on no significant hazards consideration, but will publish a notice of issuance under 10 CFR § 2.106.

In this instance, an emergency situation exists in that the proposed amendment is needed to allow the licensee to preclude an unnecessary plant shutdown. In its December 27, 2003, application, the license stated that:

> During a surveillance test on December 9, 2003, SDG 22 experienced a failure and STPNOC will not be able to complete the repairs in the current 21 day AOT. The maintenance activities are being worked on a 24-hour per day schedule until completed.
>
> Emergency approval of the proposed license amendment is needed to avoid a potential shutdown in accordance with TS 3.8.1 at the expiration of the AOT on December 30, 2003. ACTION 3.8.1.1.b would require STP Unit 2, to be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. STPNOC could not reasonably have foreseen or anticipated the failure of SDG 22. Therefore, STPNOC requests approval of this license amendment request on an emergency basis and issuance of the amendment no later than December 29, 2003 to allow implementation prior to expiration of the AOT on December 30, 2003.

The Commission expects its licensees to apply for license amendments in a timely fashion. In this situation, the NRC staff has determined that the licensee has explained, as set forth above, why this emergency situation occurred and why it could not avoid this situation. Based on the licensee's reasons set forth above, the NRC staff has determined that the licensee could not reasonably have foreseen the failure of SDG 22, and could not file the application sufficiently in advance of that event. Accordingly, the NRC staff has determined that the licensee made a timely application for the amendment, has not abused the emergency provisions of 10 CFR 50.91(a)(5), and did not itself create the emergency.

6.0 FINAL NO SIGNIFICANT HAZARDS CONSIDERATION DETERMINATION

The Commission's regulation at 10 CFR 50.92(c) states that the Commission may make a final determination that a license amendment involves no significant hazards consideration if operation of the facility in accordance with the proposed amendment would not: (1) involve a significant increase in the probability or consequences of an accident previously evaluated; or (2) create the possibility of a new or different kind of accident from any accident previously evaluated; or (3) result in a significant reduction in a margin of safety. The NRC staff has made a final determination that no significant hazards consideration is involved for the proposed amendment and that the amendment should be issued as allowed by the criteria contained in 10 CFR 50.91. The NRC staff's final determination is presented below:

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

   Response: No.

   SDG 22 provides onsite electrical power to vital systems should offsite electrical power be interrupted. It is not an initiator to any accident previously evaluated. Therefore, this extended period of operation with the SDG out-of-service will not increase the probability of an accident previously evaluated.

   The SDGs act to mitigate the consequences of design basis accidents that assume a loss of offsite power. For that purpose, redundant SDGs are provided to protect against a single failure. During the Technical Specification 14-day allowed outage time, an operating unit is allowed by the Technical Specifications to remove one of the SDGs from service, thereby losing this single-failure protection. This operating condition is considered acceptable. The consequences of a design basis accident coincident with a failure of the redundant SDG during the extended allowed outage time are the same as those during the 14-day allowed outage time. Therefore, during the period of the extended AOT, there is no significant increase in consequences of a accident previously evaluated.

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

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

   Response: No.

There are no new failure modes or mechanisms created due to plant operation for an extended period to perform repairs and post-maintenance testing of SDG 22. Extended operation with an inoperable SDG 22 does not involve any modification in the operational limits or physical design of plant systems. There are no new accident precursors generated due to the extended allowed completion time.

Therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

Response: No.

Plant operation for the proposed extension of the existing AOT for inoperable SDG 22, has been shown to have a very small impact on plant risk using the criteria of RG 1.174 and RG 1.182. During the extended allowed outage time, the electrical power system maintains the ability to perform its safety function of providing an available source of power to the Engineered Safety Feature (ESF) systems as assumed in the accident analyses. During the extended maintenance and test period, appropriate compensatory measures will be implemented to restrict risk-significant activities.

Therefore, the proposed change does not involve a significant reduction in a margin of safety as defined in the basis for any Technical Specification.

7.0 STATE CONSULTATION

In accordance with the Commission's regulations, the Texas State official was notified of the proposed issuance of the amendment. The State official had no comments.

8.0 ENVIRONMENTAL CONSIDERATION

The amendment changes a requirement with respect to installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20. The NRC staff has determined that the amendment involves no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has made a final finding that the amendment involves no significant hazards consideration. Accordingly, the amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendment.

9.0 CONCLUSION

The Commission has concluded, based on the considerations discussed above, 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 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.

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