May 16, 2007

Mr. Randall K. Edington
Senior Vice President, Nuclear
Mail Station 7602
Arizona Public Service Company
P. O. Box 52034
Phoenix, AZ 85072-2034

SUBJECT: PALO VERDE NUCLEAR GENERATING STATION, UNITS 1, 2, AND 3 - ISSUANCE OF AMENDMENTS RE: AC SOURCES - OPERATING SURVEILLANCE REQUIREMENTS (TAC NOS. MD2831, MD2832, AND MD2833)

Dear Mr. Edington:

The Commission has issued the enclosed Amendment No. 167 to Facility Operating License No. NPF-41, Amendment No. 167 to Facility Operating License No. NPF-51, and Amendment No. 167 to Facility Operating License No. NPF-74 for the Palo Verde Nuclear Generating Station, Units 1, 2, and 3, respectively. The amendments consist of changes to the Technical Specifications (TSs) in response to your application dated August 16, 2006, as supplemented by letters dated January 25 and March 8, 2007.

The amendments revise TS 3.8.1, "AC Sources - Operating," to modify the notes to TS Surveillance Requirements (SRs) 3.8.1.9, diesel generator (DG) single largest load rejection test, 3.8.1.10, DG full load rejection test, and 3.8.1.14, DG endurance and margin test to (1) allow these SRs to be performed, or partially performed, in reactor modes that currently are not allowed by the TSs, and (2) require that SRs 3.8.1.10 and 3.8.1.14 be performed at a power factor of $\leq$0.89 if performed with the emergency DGs synchronized to the grid unless grid conditions do not permit.

A copy of the related Safety Evaluation is also enclosed. The Notice of Issuance will be included in the Commission's next biweekly *Federal Register* notice.

Sincerely,

/RA/

Mel B. Fields, Senior Project Manager
Plant Licensing Branch IV
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket Nos. STN 50-528, STN 50-529,
and STN 50-530

Enclosures:
1. Amendment No. 167 to NPF-41
2. Amendment No. 167 to NPF-51
3. Amendment No. 167 to NPF-74
4. Safety Evaluation

cc w/encls: See next page

A copy of the related Safety Evaluation is also enclosed. The Notice of Issuance will be included in the Commission's next biweekly *Federal Register* notice.

Sincerely,

/RA/

Mel B. Fields, Senior Project Manager
Plant Licensing Branch IV
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cc w/encls: See next page

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ARIZONA PUBLIC SERVICE COMPANY, ET AL.

DOCKET NO. STN 50-528

PALO VERDE NUCLEAR GENERATING STATION, UNIT 1

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 167
License No. NPF-41

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

   A. The application for amendment by the Arizona Public Service Company (APS or the licensee) on behalf of itself and the Salt River Project Agricultural Improvement and Power District, El Paso Electric Company, Southern California Edison Company, Public Service Company of New Mexico, Los Angeles Department of Water and Power, and Southern California Public Power Authority dated August 16, 2006, as supplemented by letters dated January 25 and March 8, 2007, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act) and the Commission's regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, 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 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.

2. Accordingly, the license is amended by changes to the Technical Specifications and paragraph 2.C(2) of Facility Operating License No. NPF-41 as indicated in the attachment to this license amendment.

3. This license amendment is effective as of the date of issuance and shall be implemented within 120 days of the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

/RA/

Thomas G. Hiltz, Chief
Plant Licensing Branch IV
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment: Changes to the Facility
Operating License and
Technical Specifications

Date of Issuance: May 16, 2007

ARIZONA PUBLIC SERVICE COMPANY, ET AL.

DOCKET NO. STN 50-529

PALO VERDE NUCLEAR GENERATING STATION, UNIT 2

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 167
License No. NPF-51

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

   A. The application for amendment by the Arizona Public Service Company (APS or the licensee) on behalf of itself and the Salt River Project Agricultural Improvement and Power District, El Paso Electric Company, Southern California Edison Company, Public Service Company of New Mexico, Los Angeles Department of Water and Power, and Southern California Public Power Authority dated August 16, 2006, as supplemented by letters dated January 25 and March 8, 2007, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act) and the Commission's regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, 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 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.

2. Accordingly, the license is amended by changes to the Technical Specifications and paragraph 2.C(2) of Facility Operating License No. NPF-51 as indicated in the attachment to this license amendment.

3. This license amendment is effective as of the date of issuance and shall be implemented within 120 days of the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

/RA/

Thomas G. Hiltz, Chief
Plant Licensing Branch IV
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment: Changes to the Facility
Operating License and
Technical Specifications

Date of Issuance: May 16, 2007

ARIZONA PUBLIC SERVICE COMPANY, ET AL.

DOCKET NO. STN 50-530

PALO VERDE NUCLEAR GENERATING STATION, UNIT 3

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 167
License No. NPF-74

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

   A. The application for amendment by the Arizona Public Service Company (APS or the licensee) on behalf of itself and the Salt River Project Agricultural Improvement and Power District, El Paso Electric Company, Southern California Edison Company, Public Service Company of New Mexico, Los Angeles Department of Water and Power, and Southern California Public Power Authority dated August 16, 2006, as supplemented by letters dated January 25 and March 8, 2007, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act) and the Commission's regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, 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 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.

2. Accordingly, the license is amended by changes to the Technical Specifications and paragraph 2.C(2) of Facility Operating License No. NPF-74 as indicated in the attachment to this license amendment.

3. This license amendment is effective as of the date of issuance and shall be implemented within 120 days of the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

/RA/

Thomas G. Hiltz, Chief
Plant Licensing Branch IV
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment: Changes to the Facility
Operating License and
Technical Specifications

Date of Issuance: May 16, 2007

ATTACHMENT TO LICENSE AMENDMENT NOS. 167, 167, AND 167

FACILITY OPERATING LICENSE NOS. NPF-41, NPF-51, AND NPF-74

DOCKET NOS. STN 50-528, STN 50-529, AND STN 50-530

Replace the following pages of the Facility Operating Licenses Nos. NPF-41, NPF-51, and NPF-74, and 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.

Operating Licenses

Replace Page 5 of Facility Operating License No. NPF-41 with the attached Page 5.

Replace Page 6 of Facility Operating License No. NPF-51 with the attached Page 6.

Replace Page 4 of Facility Operating License No. NPF-74 with the attached Page 4.

Technical Specifications

REMOVE	INSERT
3.8.1-9	3.8.1-9
3.8.1-13	3.8.1-13

(2) Technical Specifications and Environmental Protection Plan

The Technical Specifications contained in Appendix A, as revised through Amendment No. 167, and the Environmental Protection Plan contained in Appendix B, are hereby incorporated into this license. APS shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan, except where otherwise stated in specific license conditions.

(3) Antitrust Conditions

This license is subject to the antitrust conditions delineated in Appendix C to this license.

(4) Operating Staff Experience Requirements

Deleted

(5) Post-Fuel-Loading Initial Test Program (Section 14, SER and SSER 2)*

Deleted

(6) Environmental Qualification

Deleted

(7) Fire Protection Program

APS shall implement and maintain in effect all provisions of the approved fire protection program as described in the Final Safety Analysis Report for the facility, as supplemented and amended, and as approved in the SER through Supplement 11, subject to the following provision:

APS may make changes to the approved fire protection program without prior approval of the Commission only if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire.

(8) Emergency Preparedness

Deleted

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*The parenthetical notation following the title of many license conditions denotes the section of the Safety Evaluation Report and/or its supplements wherein the license condition is discussed.

(2) Technical Specifications and Environmental Protection Plan

The Technical Specifications contained in Appendix A, as revised through Amendment No. 167, and the Environmental Protection Plan contained in Appendix B, are hereby incorporated into this license. APS shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan, except where otherwise stated in specific license conditions.

(3) Antitrust Conditions

This license is subject to the antitrust conditions delineated in Appendix C to this license.

(4) Operating Staff Experience Requirements (Section 13.1.2, SSER 9)*

Deleted

(5) Initial Test Program (Section 14, SER and SSER 2)

Deleted

(6) Fire Protection Program

APS shall implement and maintain in effect all provisions of the approved fire protection program as described in the Final Safety Analysis Report for the facility, as supplemented and amended, and as approved in the SER through Supplement 11, subject to the following provision:

APS may make changes to the approved fire protection program without prior approval of the Commission only if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire.

(7) Inservice Inspection Program (Sections 5.2.4 and 6.6, SER and SSER 9)

Deleted

(8) Supplement No. 1 to NUREG-0737 Requirements

Deleted

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*The parenthetical notation following the title of many license conditions denotes the section of the Safety Evaluation Report and/or its supplements wherein the license condition is discussed.

(1) Maximum Power Level

Arizona Public Service Company (APS) is authorized to operate the facility at reactor core power levels not in excess of 3876 megawatts thermal (100% power) through operating cycle 13, and 3990 megawatts thermal (100% power) after operating cycle 13, in accordance with the conditions specified herein.

(2) Technical Specifications and Environmental Protection Plan

The Technical Specifications contained in Appendix A, as revised through Amendment No. 167, and the Environmental Protection Plan contained in Appendix B, are hereby incorporated into this license. APS shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan, except where Otherwise stated in specific license conditions.

(3) Antitrust Conditions

This license is subject to the antitrust conditions delineated in Appendix C to this license.

(4) Initial Test Program (Section 14, SER and SSER 2)

Deleted

(5) Additional Conditions

Deleted

D. APS has previously been granted an exemption from Paragraph III.D.2(b)(ii) of Appendix J to 10 CFR Part 50. This exemption was previously granted in Facility Operating License NPF-65 pursuant to 10 CFR 50.12.

With the granting of this exemption, the facility will operate, to the extent authorized herein, in conformity with the application, as amended, the provisions of the Act, and the rules and regulations of the Commission.

E. The licensees shall fully implement and maintain in effect all provisions of the Commission-approved physical security, training and qualification, and safeguards contingency plans including amendments made pursuant to provisions of the Miscellaneous Amendments and Search Requirements revisions to 10 CFR 73.55 (51 FR 27817 and 27822) and to the authority of 10 CFR 50.90 and 10 CFR 50.54(p). The combined set of plans, which contains Safeguards Information protected under 10 CFR 73.21, is entitled: "Palo

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 167 TO FACILITY OPERATING LICENSE NO. NPF-41,

AMENDMENT NO. 167 TO FACILITY OPERATING LICENSE NO. NPF-51,

AND AMENDMENT NO. 167 TO FACILITY OPERATING LICENSE NO. NPF-74

ARIZONA PUBLIC SERVICE COMPANY, ET AL.

PALO VERDE NUCLEAR GENERATING STATION, UNITS 1, 2, AND 3

DOCKET NOS. STN 50-528, STN 50-529, AND STN 50-530

1.0 INTRODUCTION

By application dated August 16, 2006 (Agencywide Documents and Access Management System (ADAMS) Accession No. ML062630180), as supplemented by letters dated January 25 and March 8, 2007. Arizona Public Service Company (the licensee) requested changes to the Technical Specifications (TS) for Palo Verde Nuclear Generating Station (Palo Verde), Units 1, 2, and 3. The supplements dated January 25 and March 8, 2007, provided additional information that clarified the application, did not expand the scope of the application as originally noticed, and did not change the staff's original proposed no significant hazards consideration determination as published in the *Federal Register* on October 24, 2006 (71 FR 62307).

The proposed amendments would revise TS 3.8.1, "AC Sources - Operating," to modify the notes to TS Surveillance Requirements (SRs) 3.8.1.9, diesel generator (DG) single largest load rejection test, SR 3.8.1.10, DG full load rejection test, and SR 3.8.1.14, DG endurance and margin test to (1) allow these SRs to be performed, or partially performed, in reactor modes that currently are not allowed by the TSs, and (2) require that SRs 3.8.1.10 and 3.8.1.14 be performed at a power factor of $\leq$0.89 if performed with the emergency DGs synchronized to the grid unless grid conditions do not permit.

2.0 REGULATORY EVALUATION

In Section 50.36 of Title 10 of the *Code of Federal Regulations* (10 CFR), "Technical Specifications," the Commission established its regulatory requirements related to the content of TSs. Pursuant to 10 CFR 50.36, TSs are required to include items in the following five specific categories related to station operation: (1) safety limits, limiting safety system settings, and limiting control settings, (2) limiting conditions for operations (LCOs), (3) SRs, (4) design features, and (5) administrative controls. The rule does not specify the particular requirements to be included in a plant's TSs. As stated in 10 CFR 50.36(c)(2)(i), the "[l]imiting conditions for operation are the lowest functional capability or performance levels of equipment required for safe operation of the facility." The regulations in 10 CFR 50.36(c)(3), state that "[s]urveillance requirements are requirements relating to test, calibration, or inspection to assure that the necessary quality of systems and components will be maintained within safety limits, and that the limiting conditions for operation will be met."

In the submittal, the licensee appropriately identified the applicable regulatory requirements related to DG SRs as provided in 10 CFR 50, Appendix A, "General Design Criteria for Nuclear Power Plants." General Design Criterion 17, *Electric power systems*, requires "[a]n onsite electric power system and an offsite electric power system shall be provided to permit the functioning of structures, systems, and components important to safety." Criterion 17 further states that "[t]he onsite electric power supplies, including the batteries, and the onsite electric distribution system, shall have sufficient independence, redundancy, and testability to perform their safety function assuming a single failure." Electric power from the transmission network to the onsite distribution system "shall be supplied by two physically independent circuits (not necessarily on separate rights of way) 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." Criterion 17 also requires provisions to "minimize the probability of losing electric power from any of the remaining electric power supplies as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power the transmission network, or the loss of power from the onsite electric power supplies."

General Design Criterion 18, *Inspection and testing of electric power systems,*" of Appendix A to 10 CFR Part 50 states that "[e]lectric power system important to safety shall be designed to permit appropriate periodic inspection and testing of important areas and features, such as wiring, insulation, connections, and switchboards to assess the continuity of the systems and condition of their components."

Section (a)(4) of 10 CFR 50.65, "*Requirements for monitoring the effectiveness of maintenance at nuclear power plants*," states that "[b]efore performing maintenance activities (including but not limited to surveillance, post-maintenance testing, and corrective and preventative maintenance), the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities."

Regulatory Guide 1.9, Revision 3, "Selection, Design, Qualification, and Testing of Emergency Diesel Generator Units Used as Class 1E Onsite Electric Power Systems at Nuclear Power Plants," provides guidance regarding selection and testing of emergency diesel generator units.

Improved Standard Technical Specifications (STSs) have been developed based on the criteria in 10 CFR 50.36, and the NRC staff evaluation of the licensee's request to modify the specified SR was based, in part, on conformity with the EDG SRs contained in NUREG-1432, Revision 3.0, "Standard Technical Specifications Combustion Engineering Plants."

3.0 TECHNICAL EVALUATION

The detailed evaluation below will support the conclusion 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.

The staff has reviewed the licensee's justification for the proposed license amendment as described in the licensee's application dated August 16, 2006, the licensee's response to the staff's request for additional information (RAI) dated January 25, 2007, and supplemental information dated March 8, 2007. The Nuclear Regulatory Commission (NRC) staff's detailed evaluation of the proposed amendment is provided as follows:

3.1 SR 3.8.1.9, Single largest load rejection test

The current Note in SR 3.8.1.9 reads: "This surveillance shall not be performed in Mode 1, 2, 3, or 4." The revised Note will read:

> "This surveillance shall not normally be performed in MODE 1, 2, 3, or 4. However, this Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced."

The licensee stated that this surveillance demonstrates the diesel generator (DG) load response characteristics and capability to reject the largest single load or equivalent load without exceeding predetermined voltage and frequency and while maintaining a specified margin to the overspeed trip. Train A normal water chiller (842 kilowatts (kW)) and Train B auxiliary feedwater (AFW) pump (936 kW) are the bounding loads for DG-A and DG-B to reject, respectively. This SR is performed in emergency mode (not paralleled to the grid) ensuring that the DG is tested under load conditions that are as close to design-basis conditions as possible.

The licensee further stated that the proposed change modifies the note in TS SR 3.8.1.9, to allow performance of the surveillance in the prohibited modes (Modes 1, 2, 3, or 4) in order to reestablish operability following corrective maintenance provided an assessment determines that plant safety is maintained or enhanced. This assessment shall, at a minimum, consider the potential outcomes and transients associated with a failed surveillance, a successful surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the surveillance, as well as the operators' procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the surveillance is performed in Mode 1, 2, 3, or 4. Risk insights or deterministic methods may be used for this assessment.

In RAI No. 8, the staff asked the licensee to confirm that SR 3.8.1.9 will not be scheduled during periods where the potential for grid disturbance increases. In its January 25, 2007, response, the licensee made the following regulatory commitment (RCTSAI_2957438) which states:

> "The following compensatory measures shall be implemented prior to the performance of this SR in Mode 1 or 2:
>
> a. Weather conditions will be assessed, and the SR will not be scheduled when severe weather conditions and/or unstable grid conditions are predicted or present.
>
> b. No discretionary maintenance activities will be scheduled in the [Arizona Public Service Company] APS switchyard or the unit's 13.8 [kilovolt] kV power supply lines and transformers which could cause a line outage or challenge offsite power availability to the unit performing this SR.
>
> c. All activity, including access, in the [Salt River Project] (SRP) switchyard shall be closely monitored and controlled. Discretionary maintenance within the switchyard that could challenge offsite power supply availability will be evaluated in accordance with 10 CFR 50.65(a)(4) and managed on a graded approach according to risk significance."

The licensee has committed to include the above commitment in their TS bases.

Because (1) the surveillance is not being changed by the proposed amendment and can be conducted in the modes proposed after corrective maintenance by the amendment, (2) the proposed note requires a safety assessment to be performed by the licensee before conducting the surveillance to ensure that plant safety is maintained or enhanced, and (3) the full or partial performance of the SR is to demonstrate operability of the DGs, the staff concludes that an unsafe condition will not exist when the licensee performs this SR in reactor modes not currently allowed. Allowing the licensee to make the determination that performance of this SR in modes not currently allowed maintains or enhances the safety of the plant, is similar to the regulation 10 CFR 50.59 in which the licensee is allowed to make changes to the plant as described in the Updated Safety Analysis Report if the changes meet the criteria given in the regulation. The criterion for this situation is that the licensee must determine that in conducting the SR the "safety of the plant is maintained or enhanced."

Based on the above, the staff concludes that the proposed change is acceptable. In addition, the proposed note is consistent with the note provided in NUREG-1432, "Standard Technical Specifications Combustion Engineering Plants," and Industry/TS Task Force (TSTF) Traveler number TSTF-283, Revision 3.

3.2 SR 3.8.1.10, Full load rejection test

The current Note in SR 3.8.1.10 reads: "This surveillance shall not be performed in Mode 1 or 2." The proposed amendment would delete the Mode restriction and revise the Note to read as follows:

> "If performed with the DG synchronized with offsite power, it shall be performed at a power factor of $\leq$0.89. However, if grid conditions do not permit, the power factor limit is

not required to be met. Under this condition, the power factor shall be maintained as close to the limit as practicable."

The licensee stated that the load rejection test in SR 3.8.1.10 has been performed in the past by paralleling the DG with offsite power while the reactor is in Mode 5 or 6, manually raising the DG to the required 100 percent load, and then opening the DG output breaker.

Opening the DG output breaker separates the DG from its associated vital bus and allows the offsite power to continue to supply that bus. This license amendment request (LAR) is proposing that this testing also be allowed in Mode 1, 2, 3, and 4 when both DGs are required to be operable per TS 3.8.1.

The concerns associated with performing the full load rejection test in Modes 1-4 are that the DG being tested is susceptible to damage caused by grid disturbances, disconnecting the DG while paralleled to the vital buses at 100 percent rated load might cause electrical system perturbations, and the DG in test is more susceptible to tripping due to the extra protective trip relays that are in effect during test mode operations.

The licensee stated that only one DG per unit is paralleled to offsite power at any one time and any offsite grid disturbances would only possibly affect that specific DG. The onsite alternating currrent (AC) power system is fully capable of mitigating a design-basis accident or providing for a safe shutdown of the associated unit with the remaining operable DG. The staff was concerned about testing three DGs of three units simultaneously and affecting three DGs due to offsite grid disturbances. In its January 25, 2007, response (RAI No. 5), the licensee stated that the normal scheduling and risk practice for DGs is that maintenance will not be scheduled for more than one DG at a time. The most likely situation to challenge this practice would be while a particular unit's DG was being restored from scheduled maintenance and another unit's DG was to be declared inoperable for some unplanned cause. If the timing of both DGs operability runs were to coincide, there would be an evaluation performed to determine the acceptability of paralleling both these DGs to the offsite grid at the same time. It has not been a normal practice at Palo Verde to allow more than one DG to be paralleled to offsite power at the same time. Based on above, the staff's concern is resolved.

The licensee stated that sudden disconnection of a DG from the associated bus on a full load rejection test may cause a voltage fluctuation on that bus that could potentially perturb the onsite AC electrical system. The licensee stated that industry experience shows that there is no significant electrical distribution system effect on the associated bus during a full load rejection test. Furthermore, at Palo Verde when the DG full load rejection test is performed at shutdown, the voltage transients experienced by the loads on the associated bus are considered minimal (an approximate 10 percent step change (400 volts alternating current (Vac)) in the bus voltage at the 4160 Volts (V) level), with voltage recovery within 1 second. The voltage change was a smooth step change which would have no adverse impact on equipment performance. Therefore, performing load rejection tests in accordance with SR 3.8.1.10 in any mode would not cause a significant perturbation that would adversely affect the onsite AC electrical system. In RAI No. 6, the staff asked the licensee to discuss the impact of voltage transient on degraded voltage relay. In its March 8, 2007, RAI response, the licensee stated that degraded voltage relays have a time delay of 31.8 seconds (TS SR 3.3.7.3 requires this time delay to be between 28.6 and 35 seconds), so they will not be affected by the short-duration voltage transients caused by testing. The magnitude and duration of the transient voltage dip would not be significantly affected by the bus loading or voltage. However, the reactive power level of the DG prior to the load reject will affect the steady-state voltage change. At a generation level of 5500 kW at 0.89 power factor, the DG will elevate the bus voltage about 100 V above its normal level. The full load reject will return the bus voltage to the same level that occurs any time the house loads are connected to the startup transformer without the DG paralleled to the offsite power. This is 3900 V or higher, depending on switchyard voltage and loading conditions. It is well above the degraded voltage relay setting of 3744 V (TS SR 3.3.7.3 requires this setting to be between 3697 V and 3786 V). The licensee also reviewed the effect of a DG full load rejection test transient on nonsafety-related equipment such as reactor coolant pumps when the test is performed with the house loads transferred to the startup transformer during Mode 1. The staff concluded that the transient voltage change would be well within the normal operating band of the electrical distribution system and typical of the range in which the unit operates immediately preceding and following outages.

The licensee stated that during the full load rejection test, non-emergency trip features are in effect to protect the DG from equipment damage due to equipment malfunctions or offsite grid perturbations. If an engineered safety feature (ESF) actuation emergency demands occur with these non-emergency trips in effect, the affected DG will automatically revert to the emergency mode and bypass these trips. No operator action is required. If a loss of offsite power (LOOP) occurs during testing, the DG either trips on overcurrent or continues to run, depending upon if the resulting load is in excess of the DG's load rating. If the load is excessive, the DG will trip on overcurrent and the DG breaker will trip automatically on a DG shutdown signal. Upon detection of an undervoltage on the Class 1E 4160 V bus, load shedding for all vital loads and nonpermanently connected loads from the vital bus would occur followed by resequencing of the vital loads back onto the affected bus. If the load does not exceed the DG's load rating, the DG continues to run and supply the ESF bus. The operators receive indication and alarms in the control room that the preferred power source is lost. In response to the staff's concern regarding manual resetting of the overcurrent relays (RAI No. 7), the licensee stated that the overcurrent condition would cause tripping of the DG output circuit breaker (but not the offsite power supply breaker to the Class 1E 4.16 kV ESF switchgear due to its higher setting). Then the following automatic actuations would occur:

- A DG shutdown signal would trip DG.
- The loss of voltage relays would sense the loss of voltage and initiate a LOOP signal.
- The offsite power supply breaker would trip open.
- Load shedding of the Class 1E 4.16 kV ESF bus would occur.
- The DG would restart in the emergency mode (which automatically bypasses the overcurrent trip).
- The DG output breaker would re-close onto the Class 1E 4.16 kV ESF bus when rated voltage/frequency are reached.

- Required loads would automatically resequence onto the Class 1E 4.16 kV bus.

- No manual resetting of any protective relays would be required.

If a DG circuit breaker overcurrent relay trip were to occur during this test (not related to an actual LOOP) and it was desirable to start the DG up again in the “test mode” of operation, the following would have to occur:

- The cause of the trip would be investigated and resolved.

- Manually resetting of the trip relays, including independent verification.

- Reset of the emergency DG and placing it in a “standby” condition.

The manual actions for this process would take about 30-45 minutes once the cause of the trip has been investigated and resolved.

Based on above, the staff’s finds that DG would restart in the emergency mode which automatically bypasses the overcurrent trip and hence no manual resetting of any protective relays would be required. The staff’s concern is resolved.

The licensee further stated that performing this test in Modes 1, 2, 3, and 4 does not change the potential level of risk during this test. As in Modes 5 and 6, the DG is available and capable of performing its safety functions. The determination of availability of the DG in test is consistent with the definition of unavailable in Appendix B of the Nuclear Management and Resource Council, Inc. (NUMARC) 93-01, Revision 3, “Industry Guidelines for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,” which states: “[Structures, systems and components (SSCs)] out of service for testing are considered unavailable, unless the test configuration is automatically overridden by a valid starting signal, or the function can be promptly restored either by an operator in the control room or by a dedicated operator stationed locally for that purpose. Restoration actions must be contained in a written procedure, must be uncomplicated (a single action or a few simple actions), and must not require diagnosis or repair.” The licensee indicated that the DG in test will remain available per the above guidelines. As a result, there is no increase in unavailability of the DG and there is a minimum increase in risk.

In RAI No. 8, the staff asked the licensee to confirm that SR 3.8.1.10 will not be scheduled during periods where the potential for grid disturbance increases. In its January 25, 2007, response, the licensee made a regulatory commitment (RCTSAI_2957438) which states that “The following compensatory measures shall be implemented prior to the performance of this SR in Mode 1 or 2:

a. Weather conditions will be assessed, and the SR will not be scheduled when severe weather conditions and/or unstable grid conditions are predicted or present.

b. No discretionary maintenance activities will be scheduled in the APS switchyard or the unit's 13.8 kV power supply lines and transformers which could cause a line outage or challenge offsite power availability to the unit performing this SR.

c. All activity, including access, in the SRP switchyard shall be closely monitored and controlled. Discretionary maintenance within the switchyard that could challenge offsite power supply availability will be evaluated in accordance with 10 CFR 50.65(a)(4) and managed on a graded approach according to risk significance."

In RAI No. 9, the staff asked the licensee to discuss the administrative controls to preclude performing this SR during other maintenance and test conditions that could have adverse effects on the offsite power system or plans for restricting additional maintenance or testing of safety-related systems that depend on the remaining DG as a source. In its January 25, 2007, response, the licensee stated that Palo Verde procedure 70DP-0RA05, "Assessment and Management of Risk When Performing Maintenance in Modes 1 and 2," was developed to document how Palo Verde will perform the assessments required for on-line maintenance and manage the risk resulting from these maintenance activities. The licensee stated that all planned work is evaluated prior to approval of the maintenance schedule as an integrated schedule of activities. The risk associated with those activities is part of that evaluation. The licensee stated that this evaluation would identify any high-risk plant configurations and preclude unnecessary entry into those configurations. Additionally, emergent conditions are evaluated as soon as possible after the condition is known. This evaluation includes the risk impact of the emergent condition concurrent with the previously planned activities.

The decision to proceed with any work, given an emergent condition, is contingent on this integrated evaluation of the impact on risk. Additionally, if the remaining DG were to become inoperable while the other DG is being tested, an evaluation of the actual condition at that time would be conducted using the above process along with entering any appropriate TS LCO Condition(s) (i.e., 3.8.1, Condition E). This real-time evaluation would dictate the specific actions that would be taken, up to and including possibly aborting any testing that may be in progress.

In RAI No. 10, the staff asked the licensee to discuss whether the transmission system operator is notified in advance that a DG is going to be taken out for surveillance testing on-line. In its January 25, 2007, response, the licensee stated that Palo Verde procedures 73ST-9DG01 and 73ST-9DG02 specify the following prerequisite to performing this testing: "Energy Control Center [ECC] has been notified to minimize switchyard changes that could affect the DG while paralleled to the offsite power grid."

In RAI No. 11, the staff asked the licensee to discuss what action will be taken if degraded grid conditions occur during the DG testing. In its January 25, 2007, response, the licensee stated that if degraded grid conditions occur during DG surveillance testing, action would be taken as required to remain in compliance with the plant TSs.

In the August 16, 2006, LAR, the licensee stated that the proposed change will require that this SR be performed at a power factor of $\leq$0.9 if performed with DGs synchronized to the grid unless grid conditions do not permit. For reasons discussed later in this section, this value was changed to a power factor of ≤0.89. This is consistent with NUREG-1432 and NRC-approved TSTF-276, Revision 2. This requirement ensures that the DG is tested under load conditions that are as close to design-basis conditions as possible. A power factor of 0.9 is representative of the actual inductive loading a DG would see under design-basis accident conditions. This power factor should be able to be achieved when performing this SR at power and synchronized with offsite power by transferring house loads from the auxiliary transformer to the startup transformer in order to lower the Class 1E bus voltage. Transferring house loads from the auxiliary transformer to the startup transformer is routinely performed at power, in accordance with procedure 40OP-9NA03. The circuit breakers supplying the house loads from the auxiliary and startup transformers are interlocked such that one supply breaker does not open until the alternate supply breaker is closed. This ensures that the bus remains energized during the transfer. This 'make-before-break' design ensures that the transferred loads remain in synchronism with the startup transformer voltage during the transfer, so the transfer does not result in a significant transient current surge. The house loads transferred from the auxiliary transformer to the startup transformer (approximately 40 megavolt amperes (MVA) during power operation and less than 6 MVA while shut down) are well within the 70 MVA capacity of the startup transformer. Under certain conditions, the proposed change allows the surveillance to be conducted at a power factor other than ≤0.9. These conditions occur when the grid voltage is high, and the additional field excitation needed to get the power factor to ≤0.9 results in voltages on the emergency buses that are too high. This would occur when performing this SR while shut down and the loads on the startup transformer are too light to lower the voltage sufficiently to achieve a 0.9 power factor. Under these conditions, the power factor should be maintained as close as practicable to 0.9 while still maintaining acceptable voltage limits on the emergency buses.

In other circumstances, the grid voltage may be such that the DG excitation levels needed to obtain a power factor of 0.9 may not cause unacceptable voltages on the emergency buses, but the excitation levels are in excess of those recommended for the DG. In such cases, the power factor shall be maintained as close as practicable to 0.9 without exceeding DG excitation limit.

In RAI No. 1, the staff asked the licensee to confirm that proposed power factor of ≤0.9 is the calculated worst-case power factor. In its January 25, 2007, response, the licensee provided kW, kilovolts amperes reactive (KVAR), and power factor of each DG for LOOP/Forced Shutdown and LOOP/loss-of-coolant accident (LOCA) conditions. The licensee provided the SR 3.8.1.10 and SR 3.8.1.14 test requirements. The licensee stated that the stress of electrical loading on the DGs is a function of real and reactive power levels (kW and KVAR) rather than power factor. The licensee concluded that SR 3.8.1.10 and SR 3.8.1.14 testing at the required kW loading and a power factor of ≤0.9 would be representative of the calculated inductive loading a DG would see under design-basis accident conditions. The final 2-hour loading for SR 3.8.1.14 at the TS required kW and ≤0.9 power factor would test the DGs to a greater KVAR loading than any calculated accident load KVAR. Based on its independent review, the staff finds that worst-case calculated power factor is 0.89 and calculated KVAR loading (LOOP/Forced Shutdown) for Train 'A' DGs of all three units are 2676, 2708, and 2735 KVAR. KVAR loading for the full load rejection test and 22 hours load run test is 2397-2664 KVAR. This KVAR loading does not envelope the Train 'A' DG calculated KVAR loading. Train 'A' DGs will not be tested at the calculated loading (LOOP/Forced Shutdown). The staff asked the licensee to explain why these tests cannot be performed at a power factor of less than or equal to 0.89 so that Train 'A' DG's test KVAR envelope their calculated KVAR loading. The licensee supplemented its January 25, 2007, RAI response, to staff concerns in a letter dated March 8, 2007. In its March 8 letter, the licensee revised the proposed power factor requirement in SR 3.8.1.10 from ≤0.9 to ≤0.89. Based on this revision, the staff finds that its concern is resolved.

In RAI No. 12(a), the staff asked the licensee to provide a discussion regarding the acceptable power factor during the SR 3.8.1.10 performed at high-grid voltage conditions. In its March 8, 2007, response, the licensee stated that the loads on the startup transformer during shutdowns at Palo Verde are too light to lower the voltage sufficiently to achieve a 0.89 power factor when the DG is synchronized with the grid. In this situation, the typical KVAR loading without exceeding any voltage limits is the equivalent of a unity power factor. The licensee noted that, in a letter (APS letter No. 102-03794) dated October 4, 1996, the licensee provided a description of the design and testing of the DGs that ensures that the DGs will perform at the accident loading power factor when needed. The licensee stated that when SR 3.8.1.10 is performed while shut down when the power factor limit cannot be met due to grid conditions, the current DG monitoring, maintenance activities, and surveillances ensure adequate exciter function, monitor for degradation, and ensure the DG circuitry capability to perform as designed.

In RAI No. 12(b), the staff requested assurance that the Note to SR 3.8.1.10 will not be used routinely or used for convenience. In its March 8, 2007, response, the licensee stated that the proposed amendment would allow this SR to be performed during power operations as well as while shut down. The licensee stated that grid conditions at Palo Verde do not permit a 0.89 power factor limit to be met when this SR is performed while shut down. The proposed Note allowing the new power factor limit not to be met would be used whenever this SR is performed while the plant is shut down. The licensee made a regulatory commitment (RCTSAI_2957441) which states that:

> "This SR must be performed at a lagging power factor of ≤0.89 at least once every 36 months for each DG. The first performance of this SR at a lagging power factor of ≤0.89 shall be within 36 months, plus the 9-month allowance of SR 3.0.2, from the date of implementation of TS amendment that is adding the power factor testing requirement to this SR."

On the basis of its review, the staff finds that the proposed change is acceptable based on the following:

1. Palo Verde TS currently does not require DG testing to be performed at a specified power factor. The licensee's commitment of performing this SR at a lagging power factor of ≤0.89 at least once every 36 months for each DG is an improvement from the current requirements of unity power factor while shut down.

2. Running DGs at a power factor ≤0.89 will adequately detect failures or weaknesses in the regulator and exciter components or field windings due to reactive loading without exceeding excitation system limits.

3. Weather conditions will be assessed, and the SR will not be scheduled, when severe weather conditions and/or unstable grid conditions are predicted or present.

4. No discretionary maintenance activities will be scheduled in the APS switchyard or the unit's 13.8 kV power supply lines and transformers which could cause a line outage or challenge offsite power availability to the unit performing this SR.

5. All activity, including access, in the SRP switchyard shall be closely monitored and controlled. Discretionary maintenance within the switchyard that could challenge offsite power supply availability will be evaluated in accordance with 10 CFR 50.65(a)(4) and managed on a graded approach according to risk significance.

6. DG automatically reverts back to the emergency mode without operator intervention if an emergency demand occurs while the DG is under testing.

7. There is no increase in unavailability of the DG and there is a minimum increase in risk.

8. Performing the full load rejection test at power will have insignificant effect on the electrical distribution system and the electrical grid.

3.3 SR 3.8.1.14, Endurance and margin test

The current SR 3.8.1.14 Note 2 reads: "This Surveillance shall not be performed in MODE 1 or 2." The proposed amendment would delete this Mode restriction and revise Note 2 to read:

> "If performed with the DG synchronized with offsite power, it shall be performed at a power factor of $\leq$0.89. However, if grid conditions do not permit, the power factor limit is not required to be met. Under this condition, the power factor shall be maintained as close to the limit as practicable."

The licensee stated that this surveillance is performed by paralleling the DG with offsite power source while the reactor is in Mode 5 or 6, then load the DG to 100 percent rated load for 22 hours followed by raising the load for the DG test to an over-power condition (110 percent of its full load rating) for the final 2 hours. The concerns of performing this surveillance in Modes 1 or 2 are the DG being tested is susceptible to grid disturbances and the additional protective trip features would be in place making the DG more vulnerable to a possible trip. If a fault or power disturbance were to occur while a DG is paralleled to the offsite power system in the test mode of operation, the availability of the DG for subsequent emergency operation could be adversely affected due to the potential common mode vulnerability. In the case where a disturbance affects the DG being tested, protective devices (i.e., overcurrent relays, differential relays, reverse power relays) would protect the DG from equipment damage. These features will ensure that causing the DG output breaker to trip separating the DG from its associated ESF bus protects the DG. Assuming that the DG could be quickly restored from its protective device trip, making the DG available for restart could be done promptly via operator action.

The licensee stated that as a common practice at Palo Verde, risk management considerations would ensure that this and other SRs would not be scheduled during periods where the potential for grid or bus disturbance increases (storms, grid emergencies, etc.). On-line maintenance/testing scheduling and coordination of work activities at Palo Verde are controlled as required by 10 CFR 50.65(a)(4).

The licensee stated that several events could affect the DG being tested while it is paralleled to an offsite source for testing. These events are discussed below.

(1) LOOP

If a LOOP occurs during the testing, the DG either trips on overcurrent or continues to run, depending upon if the resulting load is in excess of the DG's load rating. If the load is excessive, the DG will trip on overcurrent and the DG breaker will trip automatically on a DG shutdown signal. Upon detection of undervoltage on the Class 1E 4.16 kV bus, load shedding for all vital loads and nonpermanently connected loads from the vital bus would occur followed by the DG re-energizing the vital bus and resequencing of the vital loads back onto the affected vital bus. In RAI No. 7, the staff requested the licensee to discuss how the DG will be started and DG breaker closed once the overcurrent relay trips the DG. The licensee stated that the DG would restart in the emergency mode which automatically bypasses the overcurrent trip and hence no manual resetting of any protective relays would be required. (Refer to Section 3.2 for additional discussion.) If the load does not exceed the DG's load rating, the DG continues to run and supply vital bus. The operators receive indication and alarms in the control room that the preferred power source is lost.

(2) LOCA/Auxiliary Feedwater Actuation System (AFAS)

During testing, if an actual safety injection actuation signal/containment spray actuation signal (SIAS/CSAS) or AFAS emergency signal occurs while the DG is paralleled to the preferred power supply with the control switch in the REMOTE or LOCAL position, the DG breaker will be automatically tripped by a momentary tripping pulse. The DG will continue running and automatically revert to the emergency (isochronous) mode. All non-critical protective trip devices are bypassed during the emergency mode of operation. If a non-critical trip occurs during testing, the DG will trip. On a subsequent SIAS/CSAS, AFAS, OR LOOP, the DG will automatically start and run in the isochronous mode.

(3) LOOP with LOCA

In the case where a LOCA occurs before a LOOP, the DG output breaker will trip open, the DG will revert to the emergency (isochronous) mode while running in standby and the DG output breaker will reclose to the vital bus if a subsequent LOOP condition is detected.

In the case where a LOOP occurs before the LOCA, the DG will either continue to supply the vital bus and be placed in emergency operation by a subsequent emergency safety feature (LOCA) actuation or the DG would trip off on a generator overcurrent, restart on the LOOP condition and re-close its output breaker onto the bus in the emergency mode. A subsequent emergency safety feature would then only result in additional equipment sequencing onto the DG.

The licensee stated that during the test mode of operation of DGs, non-emergency trip features provide additional protection for the DG. These protection features make a DG that is being tested more susceptible to tripping. However, if an emergency demand occurs while the DG is under testing, the DG automatically reverts back to the emergency mode without any operator intervention. Therefore, these additional trip functions are not a significant concern during performance of the endurance and margin tests while in Modes 1 and 2.

The licensee stated that the addition of the following compensatory measures to the SR 3.8.1.14 Bases will reduce the risk involved with performing this SR in Mode 1 or 2.

The following compensatory measures shall be implemented prior to the performance of this SR in MODE 1 or 2 with the DG connected to an offsite circuit:

a. Weather conditions will be assessed, and the SR will not be scheduled when severe weather conditions and/or unstable grid conditions are predicted or present.

b. No discretionary maintenance activities will be scheduled in the APS switchyard or the unit's 13.8 kV power supply lines and transformers whch could cause a line outage or challenge offsite power availability to the unit performing this SR.

c. All activity, including access, in the SRP switchyard shall be closely monitored and controlled. Discretionary maintenance within the switchyard that could challenge offsite power supply availability will be evaluated in accordance with 10 CFR 50.65(a)(4) and managed on a graded approach according to risk significance.

The licensee further stated that performing this test in Modes 1, 2, 3, and 4 does not change the potential level of risk during this test. As in Modes 5 and 6, the DG is available and capable of performing its safety functions. The determination of availability of the DG in test is consistent with the definition of unavailable in Appendix B of NUMARC 93-01, Revision 3, which states: "SSCs out of service for testing are considered unavailable, unless the test configuration is automatically overridden by a valid starting signal, or the function can be promptly restored either by an operator in the control room or by a dedicated operator stationed locally for that purpose. Restoration actions must be contained in a written procedure, must be uncomplicated (a single action or a few simple actions), and must not require diagnosis or repair." The licensee indicated that the DG in test will remain available per the above guidelines. As a result, there is no increase in unavailability of the DG and there is a minimum increase in risk.

In the August 16, 2006, LAR, the licensee stated that the proposed change will require that this SR be performed at a power factor of $\leq$0.9 if performed with DGs synchronized to the grid unless grid conditions do not permit. For reasons discussed later in this section, this value was changed to a power factor of $\leq$0.89. This is consistent with NUREG-1432 and NRC-approved TSTF-276, Revision 2. This requirement ensures that the DG is tested under load conditions that are as close to design-basis conditions as possible. A power factor of 0.9 is representative of the actual inductive loading a DG would see under design-basis accident conditions. This power factor should be able to be achieved when performing this SR at power and synchronized with offsite power by transferring house loads from the auxiliary transformer to the startup transformer in order to lower the Class 1E bus voltage. Transferring house loads from the auxiliary transformer to the startup transformer is routinely performed at power, in accordance with procedure 40OP-9NA03. The circuit breakers supplying the house loads from the auxiliary and startup transformers are interlocked such that one supply breaker does not open until the alternate supply breaker is closed. This ensures that the bus remains energized during the transfer. This 'make-before-break' design ensures that the transferred loads remain in synchronism with the startup transformer voltage during the transfer, so the transfer does not result in a significant transient current surge. The house loads transferred from the auxiliary transformer to the startup transformer (approximately 40 MVA during power operation and less than 6 MVA while shut down) are well within the 70 MVA capacity of the startup transformer. Under certain conditions, the proposed change allows the surveillance to be conducted at a power factor other than ≤0.9. These conditions occur when the grid voltage is high, and the additional field excitation needed to get the power factor to ≤0.9 results in voltages on the emergency buses that are too high. This would occur when performing this SR while shut down and the loads on the startup transformer are too light to lower the voltage sufficiently to achieve a 0.9 power factor. Under these conditions, the power factor should be maintained as close as practicable to 0.9 while still maintaining acceptable voltage limits on the emergency buses.

In other circumstances, the grid voltage may be such that the DG excitation levels needed to obtain a power factor of 0.9 may not cause unacceptable voltages on the emergency buses, but the excitation levels are in excess of those recommended for the DG. In such cases, the power factor shall be maintained as close as practicable to 0.9 without exceeding DG excitation limit.

In RAI No. 1, the staff asked the licensee to confirm that proposed power factor of ≤0.9 is the calculated worst-case power factor. In its January 25, 2007, response, the licensee provided kW, KVAR, and power factor of each DG for LOOP/Forced Shutdown and LOOP/LOCA conditions. The licensee provided the SR 3.8.1.10 and SR 3.8.1.14 test requirements. The licensee stated that the stress of electrical loading on the DGs is a function of real and reactive power levels (kW and KVAR) rather than power factor. The licensee concluded that SR 3.8.1.10 and SR 3.8.1.14 testing at the required kW loading and a power factor of ≤0.9 would be representative of the calculated inductive loading a DG would see under design-basis accident conditions. The final 2-hour loading for SR 3.8.1.14 at the TS required kW and ≤0.9 power factor would test the DGs to a greater KVAR loading than any calculated accident load KVAR. Based on its independent review, the staff finds that worst-case calculated power factor is 0.89 and calculated KVAR loading (LOOP/Forced Shutdown) for Train 'A' DGs of all three units are 2676, 2708, and 2735 KVAR. KVAR loading for full load rejection test and 22 hours load run test is 2397-2664 KVAR. This KVAR loading does not envelope the Train 'A' DG calculated KVAR loading. Train 'A' DGs will not be tested at the calculated loading (LOOP/Forced Shutdown). The staff asked the licensee to explain why these tests cannot be performed at a power factor of less than or equal to 0.89 so that Train 'A' DG's test KVAR envelope their calculated KVAR loading. The licensee supplemented its January 25, 2007, RAI response, to staff concerns in a letter dated March 8, 2007. In its March 8 letter, the licensee revised the proposed power factor requirement in SR 3.8.1.14 from ≤0.9 to ≤0.89. Based on this revision, the staff finds that its concern is resolved.

In RAI No. 12(a), the staff asked the licensee to provide a discussion regarding the acceptable power factor during the SR 3.8.1.14 performed at high-grid voltage conditions. In its March 8, 2007, response, the licensee stated that the loads on the startup transformer during shutdowns at Palo Verde are too light to lower the voltage sufficiently to achieve a 0.89 power factor when the DG is synchronized with the grid. In this situation, the typical KVAR loading without exceeding any voltage limits is the equivalent of a unity power factor. The licensee noted that, in a letter (APS letter No. 102-03794) dated October 4, 1996, the licensee provided a description of the design and testing of the DGs that ensures that the DGs will perform at the accident loading power factor when needed. The licensee stated that when SR 3.8.1.14 is performed while shut down when the power factor limit cannot be met due to grid conditions, the current DG monitoring, maintenance activities, and surveillances ensure adequate exciter function, monitor for degradation, and ensure the DG circuitry capability to perform as designed.

In RAI No. 12(b), the staff requested assurance that the Note to SR 3.8.1.14 will not be used routinely or used for convenience. In its March 8, 2007, response, the licensee stated that the proposed amendment would allow this SR to be performed during power operations as well as while shut down. The licensee stated that grid conditions at Palo Verde do not permit a 0.89 power factor limit to be met when this SR is performed while shut down. The proposed Note allowing the new power factor limit not to be met would be used whenever this SR is performed while the plant is shut down. The licensee made a regulatory commitment (RCTSAI_2957441) which states that:

> "This SR must be performed at a lagging power factor of $\leq$0.89 at least once every 36 months for each DG. The first performance of this SR at a lagging power factor of $\leq$0.89 shall be within 36 months, plus the 9-month allowance of SR 3.0.2, from the date of implementation of TS amendment that is adding the power factor testing requirement to this SR."

On the basis of its review, the staff finds that the proposed change is acceptable based on the following:

1. Palo Verde TS currently does not require DG testing to be performed at a specified power factor. The licensee's commitment of performing this SR at a lagging power factor of $\leq$0.89 at least once every 36 months for each DG is an improvement from the current requirements of unity power factor while shut down.

2. Running DGs at a power factor $\leq$0.89 will adequately detect failures or weaknesses in the regulator and exciter components or field windings due to reactive loading without exceeding excitation system limits.

3. Weather conditions will be assessed, and the SR will not be scheduled, when severe weather conditions and/or unstable grid conditions are predicted or present.

4. No discretionary maintenance activities will be scheduled in the APS switchyard or the unit's 13.8 kV power supply lines and transformers which could cause a line outage or challenge offsite power availability to the unit performing this SR.

5. All activity, including access, in the SRP switchyard shall be closely monitored and controlled. Discretionary maintenance within the switchyard that could challenge offsite power supply availability will be evaluated in accordance with 10 CFR 50.65(a)(4) and managed on a graded approach according to risk significance.

6. DG automatically reverts back to the emergency mode without operator intervention if an emergency demand occurs while the DG is under testing.

7. There is no increase in unavailability of the DG and there is a minimum increase in risk.

3.4 Regulatory Commitments

Regulatory Commitment	Due Date
RCTSAI_2957438 Upon implementation of the TS amendment requested in letter no. 102-05546, dated August 16, 2006, the following compensatory measures for SR 3.8.1.9 and SR 3.8.1.10 would be added to the TS Bases, as shown in the TS Bases markup pages: The following compensatory measures shall be implemented prior to the performance of this SR in Mode 1 or 2: a. Weather conditions will be assessed, and the SR will not be scheduled, when severe weather conditions and/or unstable grid conditions are predicted or present. b. No discretionary maintenance activities will be scheduled in the APS switchyard or the unit's 13.8 kV power supply lines and transformers which could cause a line outage or challenge offsite power availability to the unit performing this SR. c. All activity, including access, in the SRP switchyard shall be closely monitored and controlled. Discretionary maintenance within the switchyard that could challenge offsite power supply availability will be evaluated in accordance with 10 CFR 50.65(a)(4) and managed on a graded approach according to risk significance.	Upon implementation of the TS amendment requested in letter no. 102-05546, dated August 16, 2006.
RCTSAI_2957441 Upon implementation of the TS amendment requested in letter no. 102-05546, dated August 16, 2006, the following requirements will be added to the TS Bases for SR 3.8.1.10 and SR 3.8.1.14 as shown in the TS Bases markup pages: This SR must be performed at a lagging power factor of $\leq$0.89 at least once every 36 months for each DG. The first performance of this SR at a lagging power factor of $\leq$0.89 shall be within 36 months, plus the 9-month allowance of SR 3.0.2, from the date of implementation of TS amendment that is adding the power factor testing requirement to this SR.	Upon implementation of the TS amendment requested in letter no. 102-05546, dated August 16, 2006.

In its January 25 and March 8, 2007 letters, the licensee provided a list of compensatory actions that will be implemented upon implementation of the TS amendment. The compensatory measures are itemized in sections 3.1, 3.2, and 3.3 of this Safety Evaluation. The staff considers the regulatory commitment to add the compensatory measures in the TS Bases to be sufficient for the purpose of approving the licensee's amendment request.

4.0 STATE CONSULTATION

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

5.0 ENVIRONMENTAL CONSIDERATION

The amendments change 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 amendments involve 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 previously issued a proposed finding that the amendments involve no significant hazards consideration, and there has been no public comment on such finding published October 24, 2007 (71 FR 62307). Accordingly, the amendments meet 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 amendments.

6.0 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 amendments will not be inimical to the common defense and security or to the health and safety of the public.

Principal Contributor: A. Pal

Date: May 16, 2007