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TALEN ENERGY

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10CFR50.90

U. S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555-0001

SUSQUEHANNA STEAM ELECTRIC STATION
PROPOSED LICENSE AMENDMENTS TO REVISE DIESEL GENERATOR SURVEILLANCE REQUIREMENTS WITH NEW STEADY STATE VOLTAGE AND FREQUENCY LIMITS
PLA-7471

Docket Nos. 50-387 and 50-388

In accordance with the provisions of 10 CFR 50.90, *"Application for amendment of license, construction permit, or early site permit,"* Susquehanna Nuclear, LLC (Susquehanna) proposes new amendments for Susquehanna Steam Electric Station (SSES) Units 1 and 2, Operating Licenses NPF-14 and NPF-22. The proposed changes will revise certain Surveillance Requirements (SRs) in Technical Specification (TS) 3.8.1 "AC [Alternating Current] Sources-Operating." The requests are for changes in the use of steady state voltage and frequency acceptance criteria for onsite standby power source of the diesel generators (DGs), allowing for the use of new and more conservative design analysis. The new design analysis continues to ensure that accident mitigation equipment can perform as designed, while also relying upon narrowed limits for DG steady state allowable voltage and frequency requirements for the affected TS SRs.

Justifications for the proposed amendments are in the Enclosure. The proposed amendments do not involve a significant hazards consideration.

Compliance with the intent of existing TS is being administratively controlled, consistent with guidance of NRC Administrative Letter (AL) 98-10, *"Dispositioning of Technical Specifications that are Insufficient to Assure Plant Safety,"* to assure that plant safety is maintained. The proposed amendments are in accordance with the guidance of AL 98-10 because these changes are in part to address resolving non-conservative TS requirements for which conservative administrative controls are in place. The non-conservatism involves the current use of an increased minimum acceptable steady-state voltage in design analysis, and for DG testing. Other changes are more generally associated with the use of the more conservative design analysis in support of having new and narrowed acceptance criteria for both voltage and frequency limits for DG testing.

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Enclosure 1 provides an evaluation of the proposed changes. Attachments 1 and 2 contain the TS and TS Bases markups. Attachment 3 contains excerpts of some referenced calculations for additional information.

Both the Plant Operations Review Committee (PORC) and Nuclear Safety Review Board (NSRB) have reviewed the proposed changes in accordance with requirements of the Susquehanna Quality Assurance requirements.

Susquehanna requests approval of the proposed license amendment requests within one year of the submittal date or by January 31, 2018. There will be no hardware or modifications to plant equipment that are required and approval will not be operationally significant to planned refueling outages. Implementation of the proposed amendments will have a targeted implementation period of 60 days.

Pursuant to 10 CFR 50.91, *"Notice for public comment; State consultation,"* paragraph (b), Susquehanna is notifying the Commonwealth of Pennsylvania of this application for license amendments by transmitting a copy of this letter and it's supporting attachments to the designated state official.

There are no new regulatory commitments contained in this submittal.

Should you have any questions regarding this submittal, please contact Mr. Jason Jennings, Manager – Nuclear Regulatory Affairs at (570) 542-3155.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on: 1/25/17

Sincerely,

R. J. Franssen

Enclosure: Evaluation of Proposed Amendment

Attachments:
1. Technical Specification Changes (Mark-ups) – Units 1 and 2
2. Technical Specification Bases Changes (Mark-ups) - Units 1 and 2 (For Information Only)
3. Excerpts of Referenced Calculations (For Information Only)

Copy: NRC Region I
Ms. L. H. Micewski, NRC Sr. Resident Inspector
Ms. T. E. Hood, NRC Project Manager
Mr. M. Shields, PA DEP/BRP

Enclosure to PLA-7471

Susquehanna Nuclear, LLC
Evaluation of Proposed Amendment

EVALUATION OF PROPOSED AMENDMENT

Subject: Proposed License Amendments to Revise Diesel Generator Surveillance Requirements with new Steady State Voltage and Frequency Limits

1. DESCRIPTION

Susquehanna Nuclear, LLC (Susquehanna) proposes new amendments to the Susquehanna Steam Electric Station (SSES) Units 1 and 2 Operating Licenses, NPF-14 and NPF-22, to revise certain surveillance requirements (SRs) in Technical Specification (TS) 3.8.1 "AC [Alternating Current] Sources-Operating." The requests are for changes in the use of steady state voltage and frequency acceptance criteria for the onsite standby power sources of the diesel generators (DG), allowing for the use of a new and more conservative design analysis. The new design analysis continues to ensure that accident mitigation equipment can perform as designed, while also relying upon narrowed limits for DG steady state allowable voltage and frequency requirements for the affected TS SRs.

Currently, the TS SRs have steady state DG voltage limits of ≥3793 V and ≤4400 V, and steady state DG frequency limits of ≥58.8 Hz and ≤61.2 Hz. The proposed amendments revise the DGs' steady state voltage limits to ≥4000 V and ≤4400 V and the steady state DG frequency limits to ≥59.3 Hz and ≤60.5 Hz.

Implementing the requested changes will also resolve non-conservative SRs in current TS that are specific to an approved design analysis that is already in place. Increasing the minimum acceptable steady-state voltage for the DGs, a change from 3793 V to 4000 V will remove this non-conservatism. The requested changes are already in station surveillance procedures as appropriate conservative administrative controls, and remain within existing licensing basis. These administrative controls shall remain in place during the requested NRC review to assure plant safety. This action plan remains consistent with use of NRC Administrative Letter 98-10, "Dispositioning of Technical Specifications that are Insufficient to Assure Plant Safety," (ADAMS Accession No. ML031110108) to assure plant safety is maintained. The new design analysis for establishing new acceptance criteria for DG SRs is part of the TS change request requiring NRC review and approval.

Susquehanna requests approval of the proposed license amendment requests within one year of the submittal date or by January 31, 2018. There will be no new hardware or modifications to plant equipment that would be required, and approval would not be operationally significant to planned refueling outages. Implementation of the proposed amendments would then be scheduled to occur within 60 days.

Mark-ups of the proposed changes to the TS of both units are in Attachment 1. Associated changes to the TS Bases are in the mark-ups provided for information in Attachment 2. Additional information is also in Attachment 3 containing excerpts of some referenced calculations.

2. PROPOSED CHANGE

The proposed changes involve certain surveillance requirements (SRs) for Units 1 and 2 Technical Specification (TS) 3.8.1 "AC [Alternating Current] Sources-Operating." Specifically, the changes would revise the allowable steady state voltage and frequency acceptance criteria for the DGs. The DG minimum steady state voltage will be increased from ≥3793 V to ≥4000 V, and the steady state frequency limits would be narrowed to ≥59.3 Hz and ≤60.5 Hz.

In summary, the proposed changes will affect the following SRs:

SR 3.8.1.7	Monthly Operability
SR 3.8.1.9	Load Reject
SR 3.8.1.11	Loss of Offsite Power (LOOP)
SR 3.8.1.12	Loss of Coolant Accident (LOCA)
SR 3.8.1.15	Hot Restart
SR 3.8.1.19	LOCA/LOOP
SR 3.8.1.20	Simultaneous Start of all four Diesels

The details of these proposed changes in the SRs are as follows:

Current SR 3.8.1.7

Verify each DG starts from standby condition and achieves, in ≤10 seconds, voltage ≥3793 V and frequency ≥58.8 Hz, and after steady state conditions are reached, maintains voltage ≥3793 V and ≤4400 V and frequency ≥58.8 Hz and ≤61.2 Hz.

Revised SR 3.8.1.7

Verify each DG starts from standby condition and achieves, in ≤10 seconds, voltage ≥3793 V and frequency ≥58.8 Hz, and after steady state conditions are reached, maintains voltage ≥4000 V and ≤4400 V and frequency ≥59.3 Hz and ≤60.5 Hz.

Current SR 3.8.1.9

Verify each DG rejects a load greater than or equal to its associated single largest post-accident load, and

a. Following load rejection, the frequency is ≤64.5 Hz,

b. Within 4.5 seconds following load rejection, the voltage is ≥3760 V and ≤4560 V, and after steady state conditions are reached, maintains voltage ≥3793 V and ≤4400 V; and

c. Within 6 seconds following load rejection, the frequency is ≥58.8 Hz and ≤61.2 Hz.

Revised SR 3.8.1.9

Verify each DG rejects a load greater than or equal to its associated single largest post-accident load, and

a. Following load rejection, the frequency is ≤64.5 Hz;

b. Within 4.5 seconds following load rejection, the voltage is ≥3760 V and < 4560 V, and after steady state conditions are reached, maintains voltage ≥4000 V and ≤4400 V; and

c. Within 6 seconds following load rejection, the frequency is ≥59.3 Hz and ≤60.5 Hz.

Current SR 3.8.1.11

Verify on an actual or simulated loss of offsite power signal:

a. De-energization of 4.16 kV ESS buses;

b. Load shedding from 4.16 kV ESS buses; and

c. DG auto-starts from standby condition and:

   1. energizes permanently connected loads in ≤10 seconds,

   2. energizes auto-connected shutdown loads through individual load timers,

   3. maintains steady state voltage ≥3793 V and ≤4400 V,

   4. maintains steady state frequency ≥58.8 Hz and ≤61.2 Hz, and

   5. supplies permanently connected loads for ≥5 minutes.

Revised SR 3.8.1.11 Verify on an actual or simulated loss of offsite power signal:

a. De-energization of 4.16 kV ESS buses;

b. Load shedding from 4.16 kV ESS buses; and

c. DG auto-starts from standby condition and:

   1. energizes permanently connected loads in ≤10 seconds,

   2. energizes auto-connected shutdown loads through individual load timers,

   3. maintains steady state voltage ≥4000 V and ≤4400 V,

   4. maintains steady state frequency ≥59.3 Hz and ≤60.5 Hz, and

   5. supplies permanently connected loads for ≥5 minutes.

Current SR 3.8.1.12 Verify, on an actual or simulated Emergency Core Cooling System (ECCS) initiation signal, each DG auto-starts from standby condition and:

a. In ≤10 seconds after auto-start achieves voltage ≥3793 V, and after steady state conditions are reached, maintains voltage ≥3793 V and ≤4400 V;

b. In ≤10 seconds after auto-start achieves frequency ≥58.8 Hz, and after steady state conditions are reached, maintains frequency ≥58.8 Hz and ≤61.2 Hz;

c. Operates for ≥5 minutes;

d. Permanently connected loads remain energized from the offsite power system; and

e. Emergency loads are energized or auto-connected through the individual load timers from the offsite power system.

Revised SR 3.8.1.12	Verify, on an actual or simulated Emergency Core Cooling System (ECCS) initiation signal, each DG auto-starts from standby condition and: a. In ≤10 seconds after auto-start achieves voltage ≥3793 V, and after steady state conditions are reached, maintains voltage ≥4000 V and ≤4400 V; b. In ≤10 seconds after auto-start achieves frequency ≥58.8 Hz, and after steady state conditions are reached, maintains frequency ≥59.3 Hz and ≤60.5 Hz; c. Operates for ≥5 minutes; d. Permanently connected loads remain energized from the offsite power system; and e. Emergency loads are energized or auto-connected through the individual load timers from the offsite power system.
Current SR 3.8.1.15	Verify each DG starts and achieves, in ≤10 seconds, voltage ≥3793 V and frequency ≥58.8 Hz and after steady state conditions are reached, maintains voltage ≥3793 V and ≤4400 V and frequency ≥58.8 Hz and ≤61.2 Hz.
Revised SR 3.8.1.15	Verify each DG starts and achieves, in ≤10 seconds, voltage ≥3793 V and frequency ≥58.8 Hz and after steady state conditions are reached, maintains voltage ≥4000 V and ≤4400 V and frequency ≥59.3 Hz and ≤60.5 Hz.

Current SR 3.8.1.19 — Verify on an actual or simulated loss of offsite power signal in conjunction with an actual or simulated ECCS initiation signal:

a. De-energization of 4.16 kV ESS buses;

b. Load shedding from emergency buses; and

c. DG auto-starts from standby condition and:

1. energizes permanently connected loads in ≤10 seconds,

2. energizes auto-connected emergency loads through individual load timers,

3. achieves steady state voltage ≥3793 V and ≤4400 V,

4. achieves steady state frequency ≥58.8 Hz and ≤61.2 Hz, and

5. supplies permanently connected and auto-connected emergency loads for ≥5 minutes.

Revised SR 3.8.1.19 — Verify on an actual or simulated loss of offsite power signal in conjunction with an actual or simulated ECCS initiation signal:

a. De-energization of 4.16 kV ESS buses;

b. Load shedding from emergency buses; and

c. DG auto-starts from standby condition and:

1. energizes permanently connected loads in ≤10 seconds,

2. energizes auto-connected emergency loads through individual load timers,

3. achieves steady state voltage ≥4000 V and ≤4400 V,

4. achieves steady state frequency ≥59.3 Hz and ≤60.5 Hz, and

5. supplies permanently connected and auto-connected emergency loads for ≥5 minutes.

Current SR 3.8.1.20 — Verify, when started simultaneously from standby condition, each DG achieves, in ≤10 seconds, voltage ≥3793 V and frequency ≥58.8 Hz and after steady state conditions are reached, maintains voltage ≥3793 V and ≤4400 V and frequency ≥58.8 Hz and ≤61.2 Hz.

Revised SR 3.8.1.20 Verify, when started simultaneously from standby condition, each DG achieves, in ≤10 seconds, voltage ≥3793 V and frequency ≥58.8 Hz and after steady state conditions are reached, maintains voltage ≥4000 V and ≤4400 V and frequency ≥59.3 Hz and ≤60.5 Hz.

Implementing the proposed changes in TS resolves non-conservative SRs, addressing a needed increase in the DG's minimum acceptable steady state voltage from 3793 V to 4000 V. The proposed changes also address the narrowing of the steady state frequency limits for the DGs to assure the requirements of Regulatory Guide (RG) 1.9 are met.

3. BACKGROUND

The DGs provide a highly reliable, self-contained source of power to the 4.16 kV engineered safeguards bus in the event of a complete loss of off-site power. The DGs provide sufficient power for the electrical loads required for a simultaneous shutdown of both reactors. This includes the loads required to mitigate the effects of a design bases Loss of Coolant Accident (LOCA) on one unit with a complete loss of off-site power plus a single failure in the on-site power system, (such as the loss of one DG) concurrent with a safe shutdown on the other unit. DGs A thru D can supply their respective 4.16 kV engineered safeguards bus for both units. Diesel Generator E is a plug-in spare, which can be substituted for any one of the other four DGs A, B, C or D, and therefore can power any one of the four 4.16 kV engineered safeguards buses.

DGs A thru D are identical in construction and equipment, with each rated at 4,000 kW. Diesel Generator E is a larger unit and rated at 5,000 kW. Diesel Generator E is located in a separate building approximately 250 feet away from the DGs A thru D bays.

3.1 OVERVIEW ON THE NON-CONSERVATISM IN CURRENT TS (MINIMUM STEADY STATE VOLTAGE)

The proposed changes will eliminate a non-conservative requirement in affected surveillances, where the steady state minimum voltage of 3793 V cannot assure all safety related equipment would load onto the Engineered Safeguard System (ESS) bus during a Loss of Coolant Accident and/or Loss of Offsite Power (LOCA/LOOP). The 3793 V represents 91.2% of nominal 4.16 kV bus voltage and is the lowest expected setting due to tolerance of the Degraded Voltage Relays (DVRs), set at 93%. The degraded grid voltage protection scheme, when actuated, sheds all non-permanently connected loads on an ESS bus and opens offsite power breakers to the subject bus when insufficient voltage from the offsite power sources is present. If the DG supplies voltage to the ESS bus at the lower steady state limit of 3793 V, the DVRs will not reset and the load shed signal will remain, thus preventing emergency equipment from loading onto the bus. To allow the reset of the 4160 V degraded grid protection logic, the DG minimum steady state voltage should be increased above the maximum value of the DVR reset voltage of 94.68% of the 4.16 kV bus (3938 V). The original value of 3793 V was selected as it represents the lowest expected setting of the DVRs. It also represents a conservative bus value allowed when considering voltage drops to the terminals of 4000 V motors, whose minimum operating

voltage is specified as 90% or 3600 V, and other equipment, down through the 120 V level, where minimum operating voltage is usually by design basis of 90% nameplate rating.

As directed in NRC Administrative Letter 98-10, non-conservative TS require the establishment of administrative controls to ensure the significance of the impacted equipment maintains their safety functions. Administrative controls have been established for this condition and termed compensatory. They include:

1. Revising procedures to raise the minimum steady state voltage limit from 3793 V to 4000 V, (a value above the maximum value of the DVR reset voltage); and,

2. Issue an operator directive that when restoring the ESS Bus to the offsite power source, the DG voltage should not be set below 4000 V.

3.2 OTHER CHANGES REGARDING FREQUENCY

The new design analysis for the DGs will also rely upon a change in the minimum steady state frequency from 58.8 Hz to 59.3 Hz and reduces the required maximum steady state frequency from 61.2 Hz to 60.5 Hz for all DGs A thru E and all associated surveillances. This reflects the new design requirements supporting the more conservative DG surveillance acceptance criteria.

DG E was added to the standby power system in 1987, after both Units 1 and 2 commercial operation start dates. Due to the time difference for design of the DGs, some of the requirements for DG E design differ from DG A thru D. One major difference is identified in section 8.1 of the FSAR, where IEEE and NRC Regulatory Guide (RG) standards for DG performance are described. In FSAR Section 8.1.6.1.c, the design of DG E is compliant to RG 1.9, Revision 2, frequency requirements. This requirement describes that the frequency during transient periods cannot fall below 95% of nominal or 57 Hz. The requirement also describes the steady state frequency should be within 2% of 60 Hz nominal, or 58.8 Hz.

In FSAR Section 8.1.6.1.b, the design of DGs A thru D is to RG 1.9, Revision 0, and the design takes exception to the 57 Hz minimum frequency requirement during transient periods. DGs A thru D design basis adheres to the RG 1.9 Revision 0 requirement that the frequency should be within 2% of 60 Hz nominal, or 58.8 Hz.

The adherence to RG 1.9 requirement of 2% for steady state frequency requirement of all DGs A thru E is in place to ensure proper operation of safety-related loads during emergency situations and during routine surveillances. The ± 2% or ± 1.2 Hz acceptance criteria is justified by a frequency calculation and there are no impacts on the operability of the connected equipment. The ability of the DGs to perform their safety-functions are not affected by the existing steady state frequency limits regulated by RG 1.9.

During recent LOCA/LOOP surveillance tests, frequencies of the DGs were monitored. Table 1 of this section lists the maximum dip from nominal frequency (60 Hz) on each DG during the tests. In all cases, the maximum frequency dip occurred during the transient period of the RHR pump motor start. The RHR motor is the first major and largest load applied to the DGs during the LOCA/LOOP test. The 2000 horsepower motor represents approximately 1492 kW (746 watts/horsepower * 2000 hp) of load applied to the 4000 kW DG (5000 kW for DG E). During the start of the RHR motor, the maximum frequency dip experienced on all DGs was observed at 2.0 Hz. This occurred in 2016 on DG A; 2015 on DG A; 2014 on DG E when substituted for DG A; and 2010 on DG E when substituted for DG D. As stated earlier, DGs A thru D are committed to revision 0 of RG 1.9 and take exception to transient frequencies. However, DG E is committed to revision 2 of RG 1.9 and the transient frequencies are to be considered. During the 2014 and 2010 surveillance tests, the maximum transient frequency dip was 2.0 Hz (and occurred for a brief transient of less than 1 second). If DG E was operating at its minimum steady state condition of 58.8 Hz, the frequency during this transient would be 56.8 Hz (58.8 – 2.0 Hz) taking us below the RG 1.9 requirement of 57 Hz.

Table 1 (LOCA/LOOP Surveillance Results)

Outage	Year	Diesel Generator	Maximum Frequency Dip Observe from Traces	Steady State Frequency (As-Left)
U119RIO	2016	E Substituted for B	1.25 Hz	60 Hz
		A	2.0 Hz	60 Hz
		C	1.0 Hz	60 Hz
		D	1.0 Hz	60 Hz
U217RIO	2015	E Substituted for C	1.5 Hz	60 Hz
		A	2.0 Hz	60 Hz
		B	1.25 Hz	60 Hz
		D	1.0 Hz	60 Hz
U118RIO	2014	E Substituted for A	2.0 Hz	60 Hz
		B	1.25 Hz	60 Hz
		C	1.0 Hz	60 Hz
		D	1.0 Hz	60 Hz
U216RIO	2013	E Substituted for B	1.25 Hz	60 Hz
		A	1.5 Hz	60 Hz
		C	1.0 Hz	60 Hz
		D	1.25 Hz	60 Hz

Outage	Year	Diesel Generator	Maximum Frequency Dip Observe from Traces	Steady State Frequency (As-Left)
U117RIO	2012	A	1.50 Hz	60 Hz
		B	1.0 Hz	60 Hz
		C	1.0 Hz	60 Hz
		D	1.25 Hz	60 Hz
U215RIO	2011	E Substituted for A	1.50 Hz	60 Hz
		B	1.0 Hz	60 Hz
		C	1.0 Hz	60 Hz
		D	1.0 Hz	60 Hz
U116RIO	2010	E Substituted for D	2.0 Hz	60 Hz
		A	1.4 Hz	60 Hz
		B	1.1 Hz	60 Hz
		C	1.0 Hz	60 Hz
U214RIO	2009	A	1.50 Hz	60 Hz
		B	1.0 Hz	60 Hz
		C	1.1 Hz	60 Hz
		D	1.25 Hz	60 Hz
U115RIO	2008	E Substituted for C	1.75 Hz	60 Hz
		A	1.1 Hz	60 Hz
		B	1.1 Hz	60 Hz
		D	1.1 Hz	60 Hz

3.3 OVERVIEW OF AFFECTED SRs

As stated earlier, this proposal affects SRs 3.8.1.7, 3.8.1.9, 3.8.1.11, 3.8.1.12, 3.8.1.15, 3.8.1.19 and 3.8.1.20. The balance of this section further summarizes each requirement.

SR 3.8.1.7 is a monthly operability surveillance to demonstrate the DG's capability of starting from standby conditions and achieving proper voltage and frequency within the allowable timeframe.

SR 3.8.1.9 is a bi-annual surveillance used to demonstrate the DG load response characteristics and capability to reject the largest single load without exceeding predetermined voltage and frequency values while maintaining a specified margin to the overspeed trip.

SR 3.8.1.11 is a bi-annual surveillance, which demonstrates the as-designed operation of the standby power sources during a LOOP. This test verifies all actions encountered from the LOOP, including the shedding of nonessential loads, and the energization of the ESS

buses and respective 4.16 kV loads from the DG. The DG auto-starts with an output frequency that is fixed by the electronic governor to a preset value of 60 Hz. The largest load connected to the DG under this surveillance would be its aligned ESW pump motor, which starts after the DG has reached steady state operations.

SR 3.8.1.12 is the LOCA scenario demonstrating where the DG automatically starts and achieves the required voltage and frequency within the specified time (10 seconds) from the design basis LOCA actuation signal and operates for ≥5 minutes thereafter. It also ensures that permanently connected loads and the emergency loads are energized from the offsite electrical power system on a LOCA signal, without a LOOP. The DG frequency regulation will be performed by the electronic governor. Since offsite power is available, the diesel will remain running unloaded until it is secured.

SR 3.8.1.15 is a bi-annual surveillance that demonstrates the DG can restart from a hot condition, such as subsequent to shutdown from full load temperatures, and achieves the required voltage and frequency within 10 seconds.

SR 3.8.1.19 demonstrates DG operation during LOOP actuation test signal in conjunction with an ECCS initiation signal (LOCA/LOOP). This surveillance verifies all actions encountered from the LOOP, including shedding of the non-essential loads and energization of the Engineered Safeguard System (ESS) buses and respective 4.16 kV loads from the DG. It further demonstrates the capability of the DG to automatically achieve and maintain the required voltage and frequency within the specified time.

SR 3.8.1.20 is a surveillance that recurs every ten years, in which all four DGs are started simultaneously. It demonstrates that the DG starting independence has not been compromised and that each engine can achieve proper speed within the specified time, when the DGs are started simultaneously.

4. TECHNICAL ANALYSIS

Class 1E AC Electrical Distribution System (EDS) AC sources consist of two offsite power sources (preferred and alternate) and the onsite standby power sources (DGs). The installed DGs have the capability to:

(1) start and accelerate a number of large motor loads in rapid succession while maintaining voltage and frequency within acceptable limits,

(2) provide power promptly to engineered safety features if a loss of offsite power and an accident occur during the time period, and

(3) supply power continuously to the equipment needed to maintain the plant in a safe condition if an extended loss of power occurs.

When aligned to an Engineered Safeguard System (ESS) bus, a DG starts automatically on a LOCA signal (i.e. low reactor water level or high drywell pressure signal) or on an ESS bus degraded voltage or undervoltage signal. After the DG has started, it automatically ties to its

respective bus after offsite power is disconnected as a consequence of ESS bus undervoltage or degraded voltage, independent of or coincident with a LOCA signal. The DGs also start and operate in the standby mode without tying to an ESS bus on a LOCA signal alone. Following the trip of offsite power, non-permanent loads are shed from the 4.16 kV ESS buses. When a DG is tied to the ESS Bus, individual loads are sequentially connected to their respective ESS Bus by associated load timers. The load timers control the starting permissive signal to motor breakers to prevent overloading the associated DG.

In the event of loss of normal and alternate offsite supplies, the ESS electrical loads are automatically connected to the DGs in sufficient time to provide for safe reactor shutdown and to mitigate the consequences of a Design Bases Accident (DBA) such as a LOCA.

This technical analysis includes the following discussion:

- 4.1 DG Steady State Voltage
- 4.2 DG Steady State Frequency
- 4.3 DG Steady State Variations on Plant Equipment
    - 4.3.1 DG Lube Oil
    - 4.3.2 DG Jack Water
    - 4.3.3 DG Fuel Oil Storage and Transfer System
    - 4.3.4 DG Loading
    - 4.3.5 DG Fuel Oil Consumption
    - 4.3.6 Motor Impact
    - 4.3.7 MOV Performance
    - 4.3.8 Battery Chargers
    - 4.3.9 Appendix K Analysis
    - 4.3.10 Summary

4.1 DG STEADY STATE VOLTAGE

As previously mentioned, the DG will automatically start on an ESS bus undervoltage or degraded voltage condition. The degraded voltage scheme ensures that the unit can successfully cope with a LOCA condition while being subjected to the extremely low probability event of a degraded voltage condition on the Class 1E ESS bus.

SSES utilizes multiple levels of undervoltage relays to detect degradation of AC voltage. Four undervoltage relays are connected to each 4.16 kV bus. Two of the relays on each bus (27B1 and 27B2) are currently set to dropout at 93% of the rated voltage to detect sustained degraded voltage at the 4.16 kV bus. When both the 27B1 and the 27B2 relays associated with any bus dropout coincidentally, transfer of that bus to an alternate source is initiated after 5 minutes during normal plant operation, and 10 seconds during LOCA conditions. The TS SRs currently have acceptable DG surveillance minimum steady state voltage of 3793 V, which represents approximately 91.2% of nominal 4.16 kV bus voltage, and represents the lowest expected setting due to tolerance of the DVRs set at 93%. This voltage of 3793 V is above the minimum required equipment voltage but below the degraded grid relay maximum reset value of 94.68% of the 4.16 kV bus. If the DG supplies voltage to the bus at the lower steady state limit of 3793 V and the DVRs have already actuated, the DVRs will not reset and the load shed signal will remain, thus

preventing emergency equipment from loading onto the bus. To allow the reset of the 4160 V degraded grid protection logic, the DGs' minimum steady state voltage has been increased above the upper value of the DVR reset voltage of 94.68% of the 4.16 kV bus or 3938 V, requiring an increase to the existing TS minimum steady state voltage shown in the current TS.

The method used in determining the DG's minimum steady state voltage was performed by looking at the worst-case voltage drop from the DG to an associated 4.16 kV switchgear bus. This represents the voltage differential between the 4.16 kV bus, (where the DVRs are located) and the DG, (where the surveillance voltage is taken). The worst-case voltage drop is then added to the maximum value of the degraded grid relay reset voltage of 3938 V. The DG's minimum steady state voltage was determined to be 4000 V as evaluated within the DG steady state output voltage calculation.

The selected value of 4000 V, as the established minimum value of the steady state DG voltage, will not cause undesired operation of the degraded grid relay scheme. The selected value was also evaluated to ensure compatibility with other setting values to which it might be related.

The specified maximum steady state output voltage of 4400 V is not changed in the proposed SRs. This value is equal to the maximum operating voltage specified for 4000 V motors. It ensures that in a lightly loaded distribution system, the voltage specified at the terminals of 4000 V motors is not more than the maximum rated operating voltages.

4.2 DG STEADY STATE FREQUENCY

As stated earlier, the maximum frequency transient occurs during the start of the largest load, which is a Residual Heat Removal (RHR) pump motor. If the minimum DG steady state frequency of 58.8 Hz is postulated as a starting point, then DG E frequency response is one that could dip slightly and briefly below 57 Hz. The analytical dip using such a conservative assumption is below 57 Hz, and is inconsistent with the current design that uses RG 1.9, as described in the FSAR.

The LOCA/LOOP surveillance is the only surveillance that starts a RHR pump. The frequency of the DG is in direct proportion to the DG's speed and is controlled by the electronic governor. The tuning of the electronic governor is controlled through procedures that set the frequency of the DGs to 60 Hz ± 0.1 Hz. This allows for a minimum allowable frequency setting of 59.9 Hz. As stated earlier, RG 1.9 allows for ± 2% (±1.2 Hz) margin for the DG's steady state frequency. To provide additional margin necessary for DG E to avoid dipping below the 57 Hz under transient conditions, the 2% margin allowed for steady state frequency is further reduced to 1% or 0.6 Hz. With the lowest frequency allowed by the DG electronic governor (59.9 Hz), the minimum steady state frequency for the DG becomes 59.3 Hz (e.g., 59.9 – 0.6 hertz).

The electronic governor for each DG A thru E is a Woodward Model 2301A Electronic Load Sharing and Speed Control governor. Per the vendor information, the electronic governors are capable of maintaining a steady state speed band within ± 0.25% of rated speed. With the DG being a 12-pole machine, the speed of the DG is in direct proportion

to the frequency (e.g., 600 rpm is 60 Hz). If procedures allow for a frequency of 60 Hz ± 0.1 Hz, the steady state speed of the DG will be 600 ±1 rpm, having a minimum speed setting of 599 rpm. With the electronic governor having a tolerance of 0.25%, the minimum steady state value for speed is 597.5025 rpm, or a frequency of 59.75 Hz. This is 0.45 Hz above the proposed new minimum steady state frequency of 59.3 Hz. Previous LOCA/LOOP surveillances provide evidence that the steady state frequency varies considerably less than ± 0.1 Hz during LOCA/LOOP surveillances. Therefore, a properly tuned and adjusted governor is capable of maintaining a steady state frequency above 59.3 Hz and eliminating the concern of dropping below the 57 Hz requirements for DG E under transient conditions. Test results for DGs A thru E have shown that there is minimal deviation from 60 Hz during steady state periods.

The proposed change to the frequency limits of the DGs will not affect the reliability of the DGs or adversely affect its ability to perform safety functions. The minimum steady state frequency limit of 59.3 Hz produces a 2.3 Hz drop between the DG's minimum steady state frequency and the minimum transient frequency of 57 Hz as required for DG E under RG 1.9, Revision 2. As was described above, previous LOCA/LOOP surveillances identified a maximum frequency dip of 2.0 Hz during the transient period of the RHR pump motor start. With the new minimum steady state frequency setpoint of 59.3 Hz, a 15% margin for conservatism (0.3 Hz), is then provided, allowing for a maximum transient frequency drop on DG E of 2.3 Hz.

An evaluation was performed using ETAP® Power System Analyzer software that indicates the new minimum steady state frequency will be acceptable with respect to FSAR requirements. The dynamic model for DG E was tuned to match the frequency response recorded in the latest LOCA/LOOP surveillance test for DG E. The model was set to a starting steady state frequency of 59.3 Hz. During the simulated RHR pump motor start, the frequency transient did not fall below 57 Hz.

The setpoint for determination of the maximum steady state frequency is based on an iterative approach, using voltage and frequency variations of the DG to determine the maximum continuous loading on the DG such that the DG loading does not exceed its continuous rating of 4000 kW for DG A thru D and 5000 kW for DG E. Also considered during the analysis was the effects the frequency and voltage variations would have on the DG's auxiliary equipment and various safety related equipment; and its impact not to adversely affect their capability to perform their design function to mitigate the effects of a design bases accident. This analysis is performed as part of a calculation and qualitative estimation, backed-up by a dynamic transient simulation performed in ETAP. The maximum frequency meeting this iterative approach is 60.5 Hz.

The use of the new design analysis relies in part upon a change to narrow existing steady state frequency requirements (limits) of 58.8 Hz to 61.2 Hz. The DG SRs in current TS would change to verify the DGs A thru E will auto start from a standby condition and achieve a steady state frequency of ≥59.3 Hz and ≤60.5 Hz. This narrows acceptable frequency range for DG testing, so use of the new design analysis is more conservative and safe, and it reflects the use of administrative controls that are already in place to implement the new design analysis.

4.3 DG STEADY STATE VARIATIONS ON PLANT EQUIPMENT

A new evaluation (Ref. 7.10, calculation EC-024-1035) is in use at the station that evaluates DGs total loading when accounting for both steady state frequency and voltage variations within the proposed TS ranges. The new analysis considers supplying Engineered Safety Features (ESF) loads required to mitigate the worst case Design Basis Accident (DBA) and non-ESF loads not manually initiated, to assess total loading. This analysis is currently supporting conservative implementation of administrative controls for DG testing, as it addresses the impact on the performance of systems and components relative to the proposed steady state frequency and voltage limit changes to the DGs. Excerpted portions of this evaluation are in Attachment 3-3 to this enclosure. The evaluation demonstrates the proposed change:

(1) does not in any way impact system / component operation and

(2) does not adversely affect the system / component capability to perform its intended design functions.

The DGs and associated capabilities of equipment for mitigating the consequences of a worst case DBA will continue to be met while operating within the proposed steady state frequency and voltage limits (59.3 – 60.5 Hz and 4000 – 4400 V respectively). Several key attributes were reviewed for verification of proper operation allowing for no negative impact, as follows:

4.3.1 DG Lube Oil

The DG engine contains its own lubricating oil system, which provides oil at the proper flow, pressure, temperature, and cleanliness to lubricate and cool internal moving parts. The volumetric flow rate of the engine driven lube oil pump will decrease or increase proportionately with a decrease or increase in engine speed. As such, a DG operating at the minimum steady state frequency (59.3 Hz) will reduce the volumetric flow rate of the lube oil pump by approximately 1.2%. A 1.2% decrease in this flow rate is deemed negligible, and will produce no adverse consequence since the discharge pressure of a positive displacement pump remains relatively constant and is independent of the shaft speed. The normal operating pressure of the DG engine driven lube oil pump of 50 psig is well above the engine low lube oil pressure setting of 30 psig. Therefore the small increase (+ 0.8%) and decrease (- 1.2%) in DG speed, when operating at minimum and maximum frequencies, respectively, will not adversely affect the lube oil pump discharge pressure.

4.3.2 DG Jacket Water

The DG jacket water system maintains the engine warm in a state of readiness when in standby and removes heat generated during the diesel's combustion process. The engine-driven jacket water pump is a single-stage centrifugal pump and its discharge pressure variation is proportional to the square of the change in speed. Under normal operation, the engine-driven jacket water pump pressure for DG A

and E is 30 psig, and its low-pressure alarm is 12 psig and 10 psig for DG A and E, respectively. When the DG is operating at the minimum steady state frequency (59.3 Hz), the engine-driven jacket water pressure will decrease by approximately 0.70 psig for all five DGs from its nominal value, staying well above the jacket water low-pressure alarm setpoint.

The DG overspeed trip setpoint is at 660 rpm therefore, the diesel will continue running should its steady state frequency vary to the maximum allowable value of 60.5 Hz (605 rpm). At the subject maximum frequency, the operating engine-driven jacket water pump pressure would be approximately 30.5 psig, corresponding to an approximate increase of 0.5 psig from its normal operation value. Therefore, DG frequency variations within the specified range will not adversely affect the engine-driven jacket water pump capability to provide essential cooling to the engine during operation.

4.3.3 DG Fuel Oil Storage and Transfer System

The DG fuel oil system stores and delivers fuel oil for operation of the DG engine. The capacity of the transfer pump is greater than the fuel oil consumption rate of the DG engine during operation and the pump can supply fuel oil to the DG and simultaneously increase the inventory of the day tank. When considering DG steady state operation at the minimum steady state voltage and frequency, the DG fuel oil transfer pump flow rate would decrease in the worst case by approximately 2.06%. The resulting flow capacity will still exceed the DG fuel oil transfer pump flow rate requirement for all DGs.

Conversely, DG operation at a maximum steady state voltage and frequency will increase fuel oil transfer pump flow rate. This increase in DG fuel oil transfer pump flow rate will result in increased pipe velocities and system pressures. The increased fuel oil flow in turn increases suction side losses and reduces available NPSH (NPSHa) while the decreased speed will result in decrease flow, which in turn decreases suction side losses and increases NPSHa. As such, based on the aforementioned relationship, the margin between NPSHa and the required NPSH (NPSHr) would increase by approximately 4.1% during DG steady state operation at 59.3 Hz as compared to its operation at nominal frequency (60 Hz). Conversely, NPSH margin (i.e. NPSHa – NPSHr) would decrease by approximately 3.1% when the diesel is operating at a steady state frequency of 60.5 Hz. The excess margin in NPSHa is available and is more than sufficient to compensate for the changes in pump flow rate resulting from the consideration of DG frequency and voltage variations.

4.3.4 DG Loading

The cumulative impact of the voltage and frequency variations on DG loading was evaluated for its worst case-loading scenario. FSAR loading tables 8.3-2 through 8.3-5 account for both ESF and selected non-ESF loads to DGs and ESS buses. The non-ESF loads are not required for mitigating the effects of a design basis event of LOCA/LOOP on one unit and forced shutdown of the second unit, and their

ultimate operation status is at plant operations discretion. The subject non-ESF loads account for more than 620 kW of DG A loading beyond one hour of operation under the considered DBA scenario. DG A was selected as it has the most connected loads of the DGs. When considering all ESF and non-ESF Loads with the loading conservatisms, DG A total loading at 60 minutes beyond the DBA evaluated could slightly exceed (~ 2.65% max) its continuous rating of 4000 kW for certain conditions. Consequently, DG A and E loading when considering voltage and frequency variations is further evaluated by refining the loads to remove non-ESF loads that are manually initiated during the design basis event under consideration. This is acceptable, not only because these are non-ESF loads not required to mitigate the worst case DBA, but since they are manually initiated.

Thus, without the non-ESF loads, analysis shows that for the most severe design basis event, DGs A and E total loadings under limiting voltage and frequency variations within acceptable steady state ranges are within their respective continuous rating of 4000 kW and 5000 kW, with at least approximately 9.8% and 22.5% additional margins for DG A and E, respectively.

A qualitative assessment of the diesel generator loading during all three time intervals, (i.e., 0 to 10 minutes; 10 to 60 minutes; 60 minutes and beyond) when considering only frequency variations was additionally performed for ESF loads only, and simplistically considering all ESF loads being affected by DG frequency variations. The results show for all the time intervals that DGs A, C, D and E total ESF loads remain within their continuous ratings with adequate margin remaining (~15.5% for DG A and 27.5% for DG E), to accept non-ESF loads and account for concurrent voltage variations. Therefore, the DG total loading required for mitigation of the worst case DBA evaluated will remain below its continuous rating, even with consideration of its operation at various steady state voltages and frequencies within the acceptable TS ranges, evaluated herein.

4.3.5 DG Fuel Oil Consumption

DG required fuel oil volumes for seven days of operation are determined based on DG full load continuous rating of 4000 kW for DG A thru D, and 5000 kW for DG E. The total loading of each DG required for mitigation of Unit 1 DBA with Unit 2 forced shutdown while operating within the acceptable TS steady state voltage and frequency ranges remain below their continuous ratings. DGs A thru D and DG E fuel oil tanks have respectively, approximately 1,574 gallons and 16,670 gallons of spare volume above the volume required for their seven days of continuous operation. Therefore, DG fuel oil consumption resulting from its operation within the steady state voltage and frequency ranges considered will not adversely affect the fuel oil volume required for seven days of continuous operation of each diesel. As such, there is no impact to the existing calculated DG fuel oil consumption rate.

4.3.6 Motor Impact

Safety related motors are designed to perform their safety functions with a steady state voltage ± 10% of the equipment rating. Per NEMA standard MG-2, a frequency allowance of up to 5% is permissible, provided the arithmetic sum of the frequency variation and the voltage frequency does not exceed 10%. This is very conservative. A frequency reduction reduces the synchronous speed by the same amount and causes induction motors to run slower, reducing the mechanical load and the load current of the motor. Therefore, the increase in magnetizing losses at the lower frequency is offset by a reduction in the load current losses at slower speeds.

Typical AC induction motor windings (non-EQ motors) installed in the plant have Class B or F insulation system with a 40°C ambient temperature. The lowest motor windings temperature rises, based on a maximum ambient temperature of 40°C for Class B and F insulation systems are 80°C and 105°C, respectively. The effect of frequency variations on induction motor operating temperature is also evaluated based on the proportional relationship between the motor operating temperature and the square of the horsepower to rated horsepower ratio. As such, a 5.1% increase in temperature rise is expected for an operating frequency of 60.5 Hz. A 6.9% decrease is expected for a frequency of 59.3 Hz. This small change in motor insulation temperature rise above the temperature of the cooling medium would not yield abnormal deterioration of the motor insulation system during the worst case DBA considered, or have significant impact on motor life.

Continuously operated EQ motors have a qualified life of 40 years at an operating temperature of 175°C, including a winding temperature rise of approximately 110°C. The actual motor winding temperature based on normal operating load conditions and worst-case nominal normal plant voltages is 75°C. Therefore, even when considering the effect of DG steady state frequency variations on motor operating temperature, the 40-year qualified life of EQ motors at 175°C still envelops the plant equipment's maximum service temperature with more than sufficient margin in the windings.

4.3.7 MOV Performance

DG voltage and frequency variations within allowable TS steady state limits will have an impact on motor-operated valves (MOVs) similar to the impact on other induction motors such as pump motors. Steady state frequency higher than nominal value would increase the speed of the MOV motor while lower steady state frequency would reduce the motor speed.

The MOVs are fed by the 480 V system and the motor torque capability is calculated based on the ESS 4.16 kV bus voltage, set at the minimum degraded grid voltage dropout of 91.2% (~ 3793 V). This setting represents the most degraded voltage level expected when accounting for the degraded voltage relay (DVR) tolerance prior to the bus undervoltage protection (DVR) scheme operation. The lower end of the DG allowable steady state TS voltage of 4000 V is higher by

approximately 207 V than the 4.16 kV ESS bus voltage level currently used to evaluate MOV motor torque capability. Therefore, the current calculation method for MOV motor torque capability bounds the DG minimum TS allowable steady state voltage of 4000 V.

DG operation at steady state frequency of 59.3 Hz will increase the MOV close stroke time while its operation at 60.5 Hz will slightly shorten the subject close stroke time. A slightly shorter close stroke time due to an increase in motor speed operating at higher than nominal frequency will not adversely affect the valve performance. A total of 74 MOVs are identified as critical and having a TS or FSAR stroke time limit. The stroke time of these valves, when adjusted for the effects of DG steady state frequency variations, have positive margin remaining when compared with the Limiting Value for Full Stroke Time. Therefore, even when considering the effects of DG operation at steady state voltage and frequency within their TS allowable ranges, their impact on MOV operation is negligible with no adverse impact to the Limiting Value for Full Stroke Time.

4.3.8 Battery Chargers

As part of the long-term mitigation of Unit 1 DBA and Unit 2 Forced Shutdown, the following safety related battery chargers are supplied by the DGs:

- 250V DC ESS Battery Chargers
- 125V DC Battery Chargers

Per battery charger vendor manuals, the charger will regulate output voltage within ± 0.5% of the desired steady state voltage with ± 10% variations of the AC line voltage, and AC frequency variations of ± 5% (i.e. ± 3Hz). The DG steady state voltage and frequency variation ranges considered in this analysis remain within the aforementioned ranges. Therefore, the output from the battery chargers would vary by less than 0.5%, which is considered negligible with no adverse impact.

4.3.9 Appendix K Analysis

There is no need to account for the impacts of uncertainties in site-specific Emergency Core Cooling System (ECCS) flow-rates, induced by a ≤2% reduction in diesel speed in the LOCA analysis. This conclusion is consistent with NRC regulations that do not explicitly require an analytical allowance for DG frequency uncertainties when using a methodology based on the conservatisms already specified in 10 CFR 50 Appendix K, and as allowed by 10 CFR 50.46(a)(1)(ii). In addition, these methodologies used at SSES for LOCA analysis on both units are conservative and consistent with the NRC's current expectations. Therefore, the inclusion of such an additional allowance is not needed to assure the health and safety of the public.

Susquehanna's position regarding consideration of specific uncertainties due to DG frequency and the effects on ECCS flow rates (LPCI and Core Spray) are as follows:

1. The NRC Regulations (e.g., 10 CFR 50, Appendix K and 10 CFR 50.46) do not require explicit analytical allowances to account for DG frequency uncertainties when using a methodology based on the conservatisms specified in 10 CFR 50 Appendix K, (as allowed by 10 CFR 50.46(a)(1)(ii)), and

2. The methodologies used at SSES are based on 10 CFR 50.46(a)(1)(ii) and Appendix K requirements. Thus, the methods contain sufficient conservatism such that inclusion of additional uncertainty allowances to the methods is not needed to assure the health and safety of the public.

The licensing basis for ECCS evaluations, both generically and specifically for SSES include:

<u>1973 Issue of 10 CFR 50.46</u>

CLI-73-39 (Reference 7.11) contains the opinion of the Commission in the Matter of Rulemaking Hearing, Acceptance Criteria for Emergency Core Cooling Systems for Light-Water-Cooled Nuclear Power Reactors. (Reference 7.12 contains the Federal Register Notice.)

The principal licensing requirements for ECCS evaluations are given in 10 CFR 50 Appendix K and 10 CFR 50.46. These regulations do not require specific analytical allowances to account for the small uncertainties in DG frequency or voltage.

Appendix K was issued in 1973 following extensive rulemaking hearings. During those hearings, interveners argued that the proposed Appendix K was deficient because it did not account for uncertainties. The Commission rejected that argument stating that Appendix K provides for adequate margins because of conservative features in the evaluation models, and the criteria in Appendix K, including conservative treatment of stored heat, blowdown, rate of heat generation, and the peak cladding temperature criterion. As a result, the Commission concluded the following (Reference 7.12):

> *"The Commission believes that implementation of the new regulations will ensure an adequate margin of performance of the ECCS, should a design basis LOCA ever occur. This margin is provided by the conservative features of the evaluation models and by the criteria themselves."*

In Reference 7.11, NRC also stated that:

> *"The Commission is confident, however, that the criteria and evaluation models set forth here are more than sufficiently conservative to compensate for remaining uncertainties in the models or in the data."*

1988 Revision to 10 CFR 50.46

A later addition to 10 CFR 50.46 offered an option to use a best estimate approach, which would include uncertainties. Currently, 10 CFR 50.46(a)(1)(i) discusses the option of using a realistic approach to ECCS LOCA analyses. It states, in the case in which a realistic LOCA methodology is selected, that:

> *"Except as provided in paragraph (a)(1)(ii) of this section, the evaluation model must include sufficient supporting justification to show that the analytical technique realistically describes the behavior of the reactor system during a loss-of-coolant accident. Comparisons to applicable experimental data must be made and uncertainties in the analysis method and inputs must be identified and assessed so that the uncertainty in the calculated results can be estimated. This uncertainty must be accounted for, so that, when the calculated ECCS cooling performance is compared to the criteria set forth in paragraph (b) of this section, there is a high level of probability that the criteria would not be exceeded."*

The 1988 Federal Register entry (Reference 7.13) pertaining to this change to 10 CFR 50.46 to allow the option of a realistic LOCA methodology states the following:

> *"... calculations performed using current methods and in accordance with the current requirements result in estimates of core cooling performance that are significantly more conservative than estimates based on the improved knowledge gained from this research."*

> *"This rule, while continuing to allow the use of current methods and requirements, also allows the use of more recent information and knowledge to demonstrate that the ECCS would protect the reactor during a LOCA."*

> *"It is now confirmed that the methods specified in Appendix K, combined with other analysis methods currently in use, are highly conservative and that the actual cladding temperatures which occur during a LOCA would be much lower than those calculated using Appendix K methods.*

10 CFR 50.46(a)(1)(ii) includes the option to use evaluations based on Appendix K conservative methods:

> *"Alternatively, an ECCS evaluation model may be developed in conformance with the required and acceptable features of Appendix K ECCS Evaluation Models."*

Thus, the regulations reflect that an evaluation model employing Appendix K requirements is sufficiently conservative to cover uncertainties such as a DG frequency uncertainty. Thus, analytical allowances to account for these uncertainties are not required in conjunction with this proposal.

<u>Site-Specific Methodology</u>

The AREVA methodology (Susquehanna FSAR Chapter 6.3.3) used to evaluate ECCS performance for the SSES units (Chapter 6.3.3 of the FSAR) is an NRC approved methodology using Appendix K methods and conservatisms. The Licensing Basis analyses for the SSES units thus use conservative Appendix K methods as described in 10 CFR 50.46(a)(1)(ii).

Therefore, based on the discussions provided above, (e.g., on the use of the 1973 issue of 10 CFR 50.46, and the use of the 1988 revision to 10 CFR 50.46), specific analytical allowances to account for DG frequency uncertainty are not required by NRC regulations.

Where there may be some concerns regarding the margin available in terms of calculating peak cladding temperatures (PCT), those concerns may be applicable when using best-fit LOCA analysis methodology that may apply to some PWRs units, but not to SSES, nor this proposal. For example, best-fit LOCA analysis for some PWRs may have removed some conservatism for purposes of optimizing LOCA analysis and margin to PCT, but this is not an applicable concern for SSES. Margin remains available in the SSES use of Appendix K analysis where none of the inherent conservatisms have been further optimized to remove conservatisms. The AREVA methodology used to evaluate ECCS performance for the SSES units, (FSAR Chapter 6.3.3) is an NRC approved methodology using 10 CFR 50, Appendix K methods and conservatisms. Consequently, analyses for SSES units in this manner use conservative Appendix K methods as described in 10 CFR 50.46(a)(1)(ii). There are no other evaluations that credit this margin for SSES. The proposed amendments in this request do not seek to change any aspect of this SSES licensing basis.

4.3.10 Summary

This analysis evaluated the effects of DG frequency and voltage variations in the ranges of 59.3 Hz to 60.5 Hz, and 4000 V to 4400 V, for major equipment fed by the DGs. Some of the main aspects examined included DG steady state loading, fuel oil consumption, and lube oil and jacket water systems. Additionally, the effects of DG frequency and voltage variations on motors, battery chargers, pumps and MOV performance were also evaluated. Analysis has confirmed through use of qualitative estimation and dynamic transient simulation how under the worst-case DBA, the DG loading, when operating within these frequency and voltage ranges, will not exceed their continuous ratings or fuel oil consumption rates, when supplying required ESF loads, and non-ESF not manually initiated loads, for mitigation of the worst case DBA.

When considering all loads (ESF and non-ESF) per FSAR Table 8.3-3, DG E total loading results remain significantly below rated continuous loading in all cases; while DG A total loading results in four study cases, (e.g., 4000 V, 60.5 Hz; 4160 V, 60.5 Hz; 4400 V, 59.3 Hz and 4400 V, 60.5 Hz), could slightly exceed (to a maximum ~2.6%) the DG's continuous rating of 4000 kW. However, several conservatisms including non-ESF loads manually initiated are not required for the mitigation of Unit 1 DBA and Unit 2 Forced Shutdown, and were explicitly added to the DG loading in this analysis to yield bounding results. As a result, approximately 928 kW (23.2% of the DG continuous rating) are conservatively added to the total loading results and the corresponding 23.2% margin is substantially greater than the 2.6% above.

By removing non-ESF, the DG loads remain below their respective continuous rating with adequate margins (~ 9.8% and ~ 22.5% for DGs A and E, respectively) for all steady state voltage and frequency variations within the ranges evaluated.

5. **REGULATORY SAFETY ANALYSIS**

Susquehanna Nuclear, LLC proposes to amend Susquehanna Steam Electric Station (SSES) Units 1 and 2, Facility Operating Licenses NPF-14 and NPF-22, Appendix A, Technical Specification 3.8.1, "AC Sources – Operating." The proposed amendments are for changes to certain technical specification steady state voltage and frequency acceptance criteria for emergency diesel generator (DG) surveillance testing. Steady state voltage and frequency acceptance criteria for DG testing are changing to allow for the use of new and more conservative design analysis. The changes address non-conservative minimum voltage acceptance criteria for DG steady state operation. The other changes are more generally associated with the use of the more conservative design analysis in support of having new and narrowed acceptance criteria for both voltage and frequency limits for DG testing. The new surveillance requirements help to ensure the availability of the standby electrical power supply to mitigate design basis accidents and transients, and to maintain the unit in a safe shutdown condition.

5.1 APPLICABLE REGULATORY REQUIREMENTS/CRITERIA

The proposed changes comply with the following regulations and continue to meet the intent of the applicable General Design Criteria (GDC).

10 CFR 50.36, "Technical specifications," requires in paragraph 50.36(c)(2)(ii)(C) *Criterion 3* that a technical specification limiting condition for operation be established for a structure, system, or component that is part of the primary success path and which functions or actuates to mitigate a design basis accident or transient that either assumes the failure of or presents a challenge to the integrity of a fission product barrier. The alternating current electrical power sources (AC Sources – Operating) limiting condition for operation (LCO 3.8.1) satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

10 CFR 50.36, "Technical specifications," requires in paragraph 50.36(c)(3) that technical specifications include surveillance requirements relating to test, calibration, or inspection to assure that the necessary quality of systems and components is maintained, that facility operation will be within safety limits, and that the limiting conditions for operation will be met. The technical specifications will continue to include surveillance requirements relating to emergency diesel generator testing to assure the components are maintained, facility operation will be within safety limits, and the limiting conditions for emergency diesel generator operation will be met.

The regulatory basis for TS 3.8.1 "AC Sources – Operating" is to ensure that highly reliable, self-contained source of power is supplied to SSCs important to safety in the event of a complete loss of off-site power to the associated 4.16 kV bus.

This ensures the AC electrical power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant Systems (RCS) and containment design limits are not exceeded. The operability of the AC electrical power sources is consistent with the initial assumptions of the accident analyses and is based upon meeting the design bases of the units and supporting safe shutdown of the other unit.

GDC 2, "Design bases for protection against natural phenomena," requires that SSCs important to safety shall be designed to withstand the effects of natural phenomena such as earthquakes, tornadoes, hurricanes, floods, tsunami, and seiches without loss of capability to perform their safety functions.

GDC 4, "Environmental and dynamic effects design bases," requires that SSCs important to safety shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss-of-coolant accidents.

GDC 5, "Sharing of structures, systems, and components," requires that SSCs important to safety shall not be shared among nuclear power units unless it can be shown that such sharing will not significantly impair their ability to perform their safety functions, including, in the event of an accident in one unit, an orderly shutdown and cooldown of the remaining units.

GDC 17, "Electric power systems," requires that an onsite electric power system and an offsite electric power system shall be provided to permit functioning of SSCs important to safety. The onsite electric power supplies, including the batteries, and the onsite electric distribution system, shall have sufficient independence, redundancy, and testability to perform their safety functions assuming a single failure. Provisions shall be included to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the transmission network, or the loss of power from the onsite electric power supplies.

GDC 18, "Inspection and Testing of Electric Power Systems and 10 CFR 50 Appendix B Criterion XI, "Test Control," both require established programs for assuring that the Systems Structures and Components (SSC's) are demonstrated operable on a periodic basis.

GDC 21, "Protection system reliability and testability," requires that the protection system shall be designed for high functional reliability and in-service testability commensurate with the safety functions to be performed. Such protection system shall be designed to permit periodic testing of its functioning when the reactor is in operation, including a capability to test channels independently to determine failures and losses of redundancy that may have occurred.

RG 1.9, *"Selection, Design, and Qualification of Diesel-Generator Units Used As Standby (Onsite) Electrical Power Systems at Nuclear Power Plants"* specifies the required minimum frequency during transient, and the minimum steady state frequency requirement.

DG E complies with RG 1.9, Rev. 2. Frequency and voltage limits and the basis of the continuous rating of the DG are discussed in the FSAR subsection 8.1.6.1, in the compliance statement to RG 1.9. This proposed amendment does not alter these regulatory requirements.

The Class 1E electric systems are designed to satisfy the single failure criterion in accordance with IEEE 379-1972. Class 1E equipment has been designed with the capability for periodic testing.

The proposed changes to increase the minimum steady state voltage and the setting of new frequency limits for all DGs will not adversely impact the ability of the DGs to function as designed and do not impact conformance to the applicable 10 CFR 50 Appendix A, "General Design Criteria for Nuclear Power Plants." The proposed revisions to the DG SRs are not in conflict with the 10 CFR 50.36 requirements. The new frequency limits established for the DGs remain compliant with existing FSAR design basis that rely upon RG 1.9 Revision 2, because the values are more conservative than before. Therefore, the proposed changes are consistent with all applicable regulatory requirements or criteria.

The proposed changes do not violate any requirement or recommended method for assuring the operability of the DGs and maintaining the plant design and licensing basis.

The proposed changes help verify parameters required in design analysis, already in use, to stay within the prescribed limits, and independently verifies that the values assumed in the accident analysis are satisfied. This testing is performed at the stated voltages and frequencies to assure continued operability of the DGs.

5.2 NO SIGNIFICANT HAZARDS CONSIDERATION

The proposed amendment requests changes to certain technical specification steady state voltage and frequency acceptance criteria for emergency diesel generator (DG) surveillance testing.

Susquehanna Nuclear, LLC has evaluated whether or not a significant hazards consideration is involved with the proposed amendment(s) by focusing on the three standards set forth in 10CFR50.92, "Issuance of amendment," as discussed below:

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

   Response: No

   The proposed amendment would provide more restrictive acceptance criteria for certain DG technical specification surveillance tests. The proposed acceptance criteria changes would help to ensure the DGs are capable of carrying the electrical loading assumed in the safety analyses that take credit for the operation of the DGs, would not affect the capability of other structures, systems, and components to perform their design function, and would not increase the likelihood of a malfunction.

Therefore, the proposed amendment does not significantly increase the probability or consequences of an accident previously evaluated.

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

Response: No.

The proposed changes would provide more restrictive acceptance criteria to be applied to existing technical specification surveillance tests that demonstrate the capability of the facility DGs to perform their design function. The proposed acceptance criteria changes would not create any new failure mechanisms, malfunctions, or accident initiators not considered in the design and licensing bases.

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

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

Response: No

The proposed DG surveillance requirement changes to voltage and frequency test acceptance criteria are conservative because the minimum steady state voltage increase and the narrowing of the acceptable steady-state frequency range validates use of existing design basis analysis for these test acceptance criteria. Both changes support the use of conservative administrative controls that remain in place, allowing use of the new test acceptance criteria in test procedures until technical specifications reflect these new requirements. The conduct of surveillance tests on safety related plant equipment is a means of assuring that the equipment is capable of maintaining the margin of safety established in the safety analyses for the facility. The proposed amendment does not affect DG performance as described in the design basis analyses, including the capability for the DG to attain and maintain required voltage and frequency for accepting and supporting plant safety loads, should a DG start signal occur. The proposed amendment does not introduce changes to limits established in accident analysis.

Therefore, the proposed amendment does not involve a significant reduction in a margin of safety.

Based on the above, Susquehanna Nuclear, LLC concludes that the proposed amendment(s) present no significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of "no significant hazards consideration" is justified.

5.3 CONCLUSIONS

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

6. ENVIRONMENTAL CONSIDERATION

10 CFR 51.22(c)(9) identifies certain licensing, regulatory, and administrative actions which are eligible for categorical exclusion from the requirement to perform an environmental assessment. A proposed amendment to a facility operating license which changes a requirement, or grants an exemption from any such requirement, with respect to installation or use of a facility component located within the restricted area, or which changes an inspection or a surveillance requirement does not require an environment assessment provided that:

(1) the subject amendment involves no significant hazards consideration;
(2) there is no significant change in the types or significant increase in the amounts of any effluents that may be released offsite; and
(3) there is no significant increase in individual or cumulative occupational radiation exposure.

Susquehanna has evaluated the proposed change and determined the subject change meet the criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). As such, per 10 CFR 51.22(b), an environmental assessment or an environmental impact statement is not required for this proposed amendment. Following is the basis for this determination, using the aforementioned criteria.

BASIS:

As demonstrated in the "No Significant Hazards Consideration" evaluation, the proposed change does not involve a significant hazards consideration.

The proposed amendment does not involve addition or deletion of component in the DG system or any other SSCs. Neither normal plant operation parameters nor existing DG system responses to Design Basis Accidents (DBA) or a combination of DBA as described in the FSAR would be adversely affected by the implementation of this proposed change. Change in the types or significant increase in the amounts of any effluents that may be released offsite, or significant increase in individual or cumulative occupational radiation exposure would not occur upon the setting of new limits for the DG steady state voltages and frequencies.

7. REFERENCES

7.1 FSAR
a. Section 6.3.3 ECCS Performance Evaluation
b. Section 8.1.6.1 Compliance with Regulatory Guides
c. Tables 8.3-2 thru 8.3-5 Diesel Generator Loading

7.2 10 CFR 50.46; Acceptance Criteria for Emergency Core Cooling Systems for Light-Water Nuclear Power Reactors

7.3 10 CFR 50.92; Issuance of Amendment

7.4 10 CFR 50 Appendix K; ECCS Evaluation Models

7.5 10 CFR 51.22; Criterion for Categorical Exclusion; Identification of Licensing and Regulatory Actions Eligible for Categorical Exclusion or Otherwise not Requiring Environmental Review

7.6 NRC Administrative Letter 98-10, Dispositioning of Technical Specifications that are Insufficient to Assure Plant Safety

7.7 NRC Regulatory Guide 1.9, Selection, Design, and Qualification of Diesel-Generator Units Used As Standby (Onsite) Electrical Power Systems at Nuclear Power Plants

7.8 Calculation EC-024-1014, DG Steady State Frequency Limits for DG Surveillance & Regulatory Guide 1.9

7.9 Calculation EC-024-1031, DG Steady State Output Voltage for Surveillance Tests

7.10 Calculation EC-024-1035, Evaluation of the impact of Diesel Generator (DG) Technical Specification Steady State Frequency and Voltage Variations Within Acceptable Limits

7.11 CLI-73-39, In the Matter of Rulemaking Hearing, Acceptance Criteria for Emergency Core Cooling Systems for Light-Water-Cooled Nuclear Power Reactors, Docket No. RM-50-01, December 28, 1973

7.12 Federal Register Vol 39, No. 3 – Friday, January 4, 1974 / Rules and Regulations / Acceptance Criteria for Emergency Core Cooling Systems for Light-Water-Cooled Nuclear Power Reactors

7.13 Federal Register / Vol. 53. No. 180 / Friday: September 16, 1988 / Rules and Regulations / 10 CFR 50 / Emergency Core Cooling Systems; Revisions to Acceptance Criteria

Attachment 1 to PLA-7471

Technical Specification Changes (Mark-Ups)
Units 1 and 2

3.8 Electrical Power Systems

For Information – No Changes on This Page

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. Two or more required DGs inoperable.	E.1 Restore at least three required DGs to OPERABLE status.	2 hours
F. Required Action and Associated Completion Time of Condition A, B, C, D, or E not met.	F.1 Be in MODE 3. <u>AND</u> F.2 Be in MODE 4.	12 hours 36 hours
G. One or more offsite circuits and two or more required DGs inoperable. <u>OR</u> One required DG and two offsite circuits inoperable.	G.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

---NOTE---

Four DGs are required and a DG is only considered OPERABLE when the DG is aligned to the Class 1E distribution system. DG Surveillance Requirements have been modified to integrate the necessary testing to demonstrate the availability of DG E and ensure its OPERABILITY when substituted for any other DG. If the DG Surveillance Requirements, as modified by the associated Notes, are met and performed, DG E can be considered available and OPERABLE when substituted for any other DG after performance of SR 3.8.1.3 and SR 3.8.1.7.

SURVEILLANCE		FREQUENCY
SR 3.8.1.1	Verify correct breaker alignment and indicated power availability for each offsite circuit.	In accordance with the Surveillance Frequency Control Program

(continued)

3.9 Electrical Power Systems

For Information – No Changes on This Page

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.1.2	Not Used.	
SR 3.8.1.3	-----NOTES----- 1. DG loading may include gradual loading as recommended by the manufacturer. 2. Momentary transients outside the load range do not invalidate this test. 3. This Surveillance shall be conducted on only one DG at a time. 4. This SR shall be preceded by and immediately follow, without shutdown, a successful performance of SR 3.8.1.7. 5. DG E, when not aligned to the Class 1E distribution system, may satisfy this SR using the test facility. 6. A single test will satisfy this Surveillance for both units if synchronization is to the 4.16 kV ESS bus for Unit 1 for one periodic test and synchronization is to the 4.16 kV ESS bus for Unit 2 for the next periodic test. However, if it is not possible to perform the test on Unit 2 or test performance is not required per SR 3.8.2.1, then the test shall be performed synchronized to the 4.16 kV ESS bus for Unit 1. ---------- Verify each DG is synchronized and loaded and operates for ≥ 60 minutes at a load ≥ 3600 kW and ≤ 4000 kW.	In accordance with the Surveillance Frequency Control Program

(continued)

3.10 Electrical Power Systems

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.1.4	Verify each engine mounted day tank fuel oil level is ≥ 420 gallons for DG A-D and ≥ 425 gallons for DG E.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.5	Check for and remove accumulated water from each engine mounted day tank.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.6	Verify the fuel oil transfer system operates to automatically transfer fuel oil from the storage tanks to each engine mounted tank.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.7	-------------------------------NOTES--------------------------------- 1. All DG starts may be preceded by an engine prelube period. 2. A single test at the specified Frequency will satisfy this Surveillance for both units. --- Verify each DG starts from standby condition and achieves, in ≤ 10 seconds, voltage ≥ 3793 V and frequency ≥ 58.8, and after steady state conditions are reached, maintains voltage ≥ ~~3793~~ 4000 V and ≤ 4400 V and frequency ≥ ~~58.8~~59.3 Hz and ≤ ~~61.2~~60.5 Hz.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.8	-------------------------------NOTE----------------------------------- The automatic transfer of the unit power supply shall not be performed in MODE 1 or 2. --- Verify automatic and manual transfer of unit power supply from the normal offsite circuit to the alternate offsite circuit.	In accordance with the Surveillance Frequency Control Program

(continued)

3.11 Electrical Power Systems

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.1.9	-------------------------------NOTE------------------------------- A single test at the specified Frequency will satisfy this Surveillance for both units. -- Verify each DG rejects a load greater than or equal to its associated single largest post-accident load, and: a. Following load rejection, the frequency is ≤ 64.5 Hz; b. Within 4.5 seconds following load rejection, the voltage is ≥ 3760 V and ≤ 4560 V, and after steady state conditions are reached, maintains voltage ≥ ~~3793~~ 4000 V and ≤ 4400 V; and c. Within 6 seconds following load rejection, the frequency is ≥ ~~58.8~~59.3 Hz and ≤ ~~61.2~~60.5 Hz.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.10	-------------------------------NOTES------------------------------- A single test at the specified Frequency will satisfy this Surveillance for both units. -- Verify each DG does not trip and voltage is maintained ≤ 4560 V during and following a load rejection of ≥ 4000 kW.	In accordance with the Surveillance Frequency Control Program

(continued)

3.12 Electrical Power Systems

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.11	-----------------------------NOTES--------------------------------- 1. All DG starts may be preceded by an engine prelube period. 2. This SR shall be performed for each DG on a rotational test basis and for each 4.16 kV ESS bus at the specified FREQUENCY. 3. This Surveillance shall not be performed in MODE 1, 2 or 3. ---	
	Verify on an actual or simulated loss of offsite power signal:	In accordance with the Surveillance Frequency Control Program
	a. De-energization of 4.16 kV ESS buses; b. Load shedding from 4.16 kV ESS buses; and c. DG auto-starts from standby condition and: 1. energizes permanently connected loads in ≤ 10 seconds, 2. energizes auto-connected shutdown loads through individual load timers, 3. maintains steady state voltage ≥ ~~3793~~ 4000 V and ≤ 4400 V, 4. maintains steady state frequency ≥ ~~58.8~~59.3 Hz and ≤ ~~61.2~~60.5 Hz, and 5. supplies permanently connected loads for ≥ 5 minutes.	

(continued)

3.13 Electrical Power Systems

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.1.12	-----------------------------NOTES----------------------------- 1. All DG starts may be preceded by an engine prelube period. 2. DG E, when not aligned to the Class 1E distribution system, may satisfy this SR for both units by performance of SR 3.8.1.12.a, b and c using the test facility to simulate a 4.16 kV ESS bus. SR 3.8.1.12.d and e may be satisfied with either the normally aligned DG or DG E aligned to the Class 1E distribution system. --- Verify, on an actual or simulated Emergency Core Cooling System (ECCS) initiation signal, each DG auto-starts from standby condition and: a. In ≤ 10 seconds after auto-start achieves voltage ≥ 3793 V, and after steady state conditions are reached, maintains voltage ≥ ~~3793~~ 4000 V and ≤ 4400 V; b. In ≤ 10 seconds after auto-start achieves frequency ≥ 58.8 Hz, and after steady state conditions are reached, maintains frequency ≥ ~~58.8~~59.3 Hz and ≤ ~~61.2~~60.5 Hz; c. Operates for ≥ 5 minutes; d. Permanently connected loads remain energized from the offsite power system; and e. Emergency loads are energized or auto-connected through the individual load timers from the offsite power system.	In accordance with the Surveillance Frequency Control Program

(continued)

For Information – No Changes on This Page

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.1.13	------------------------------NOTES------------------------------ 1. A single test at the specified Frequency will satisfy this Surveillance for both units. 2. DG E, when not aligned to the Class 1E distribution system, may satisfy this SR for both units by using a simulated ECCS initiation signal. --- Verify each DG's automatic trips are bypassed on actual or simulated loss of voltage signal on the 4.16 kV ESS bus concurrent with an actual or simulated ECCS initiation signal except: a. Engine overspeed; and b. Generator differential current; and c. Low lube oil pressure.	In accordance with the Surveillance Frequency Control Program

(continued)

For Information – No Changes on This Page

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.14	------------------------------NOTES------------------------------ 1. Momentary transients outside the load ranges do not invalidate this test. 2. A single test at the specified Frequency will satisfy this Surveillance for both units. 3. DG E, when not aligned to the Class 1E distribution system may satisfy this SR by using the test facility. --	
	Verify each DG operates for ≥ 24 hours:	In accordance with the Surveillance Frequency Control Program
	a. For ≥ 2 hours loaded ≥ 4400 kW and ≤ 4700 kW for DGs A through D and ≥ 5000 kW and ≤ 5500 kW for DG E; and b. For the remaining hours of the test loaded ≥ 3600 kW and ≤ 4000 kW for DGs A through D and ≥ 4500 kW and ≤ 5000 kW for DG E.	

(continued)

3.16 Electrical Power Systems

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.1.15	-----------------------------NOTES--------------------------------- 1. This Surveillance shall be performed within 5 minutes of shutting down the DG after the DG has operated ≥ 2 hours loaded ≥ 3800 kW. Momentary transients outside of load range do not invalidate this test. 2. All DG starts may be preceded by an engine prelube period. 3. A single test at the specified Frequency will satisfy this Surveillance for both units. --	
	Verify each DG starts and achieves, in ≤ 10 seconds, voltage ≥ 3793 V and frequency ≥ 58.8 and after steady state conditions are reached, maintains voltage ≥ ~~3793~~ 4000 V and ≤ 4400 V and frequency ≥ ~~58.8~~59.3 Hz and ≤ ~~61.2~~60.5 Hz.	In accordance with the Surveillance Frequency Control Program

(continued)

For Information – No Changes on This Page

3.17 Electrical Power Systems

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.1.16	------------------------------NOTES------------------------------ This SR shall be performed for each DG on a rotational test basis and for each 4.16 kV ESS bus at the specified FREQUENCY. --	
	Verify each DG: a. Synchronizes with offsite power source while loaded with emergency loads upon a simulated restoration of offsite power; b. Transfers loads to offsite power source; and c. Returns to ready-to-load operation.	In accordance with the Surveillance Frequency Control Program

(continued)

For Information – No Changes on This Page

3.18 Electrical Power Systems

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.17	------------------------------NOTES------------------------------ This SR shall be performed for each DG on a rotational test basis and for each 4.16 kV ESS bus at the specified FREQUENCY. -- Verify with a DG operating in test mode and connected to its bus, an actual or simulated ECCS initiation signal overrides the test mode by: a. Returning DG to ready-to-load operation; and b. Automatically energizing the emergency load from offsite power.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.18	------------------------------NOTE------------------------------ Load timers associated with equipment that has automatic initiation capability disabled are not required to be OPERABLE. -- Verify each sequenced load is within required limits of the design interval.	In accordance with the Surveillance Frequency Control Program

(continued)

3.19 Electrical Power Systems

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.1.19	------------------------------NOTES------------------------------ 1. All DG starts may be preceded by an engine prelube period. 2. This SR shall be performed for each DG on a rotational test basis and for each 4.16 kV ESS bus at the specified FREQUENCY. 3. This Surveillance shall not be performed in MODE 1, 2 or 3. --	
	Verify on an actual or simulated loss of offsite power signal in conjunction with an actual or simulated ECCS initiation signal: a. De-energization of 4.16 kV ESS buses; b. Load shedding from emergency buses; and c. DG auto-starts from standby condition and: 1. energizes permanently connected loads in $\leq$ 10 seconds, 2. energizes auto-connected emergency loads through individual load timers, 3. achieves steady state voltage $\geq$ ~~3793~~ 4000 V and $\leq$ 4400 V, 4. achieves steady state frequency $\geq$ ~~58.8~~59.3 Hz and $\leq$ ~~61.2~~60.5 Hz, and 5. supplies permanently connected and auto-connected emergency loads for $\geq$ 5 minutes.	In accordance with the Surveillance Frequency Control Program

(continued)

3.20 Electrical Power Systems

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.1.20	------------------------------NOTES------------------------------ 1. All DG starts may be preceded by an engine prelube period. 2. This SR does not have to be performed with DG E substituted for any DG. -- Verify, when started simultaneously from standby condition, each DG achieves, in ≤ 10 seconds, voltage ≥ 3793 V and frequency ≥ 58.8 and after steady state conditions are reached, maintains voltage ≥ ~~3793~~ 4000 V and ≤ 4400 V and frequency ≥ ~~58.8~~59.3 Hz and ≤ ~~61.2~~60.5 Hz.	In accordance with the Surveillance Frequency Control Program

For Information – No Changes on This Page

SURVEILLANCE REQUIREMENTS

---NOTES---

1. Four DGs are required and a DG is only considered OPERABLE when the DG is aligned to the Class 1E distribution system. DG Surveillance Requirements have been modified to integrate the necessary testing to demonstrate the availability of DG E and ensure its OPERABILITY when substituted for any other DG. If the DG Surveillance Requirements, as modified by the associated Notes, are met and performed, DG E can be considered available and OPERABLE when substituted for any other DG after performance of SR 3.8.1.3 and SR 3.8.1.7.

2. SR 3.8.1.21 establishes Surveillance Requirements for the Unit 1 AC sources required to support Unit 2.

SURVEILLANCE		FREQUENCY
SR 3.8.1.1	Verify correct breaker alignment and indicated power availability for each offsite circuit.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.2	Not Used.	

(continued)

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.1.3	-------------------------NOTES------------------------- 1. DG loading may include gradual loading as recommended by the manufacturer. 2. Momentary transients outside the load range do not invalidate this test. 3. This Surveillance shall be conducted on only one DG at a time. 4. This SR shall be preceded by and immediately follow, without shutdown, a successful performance of SR 3.8.1.7. 5. DG E, when not aligned to the Class 1E distribution system, may satisfy this SR using the test facility. 6. A single test will satisfy this Surveillance for both units if synchronization is to the 4.16 kV ESS bus for Unit 2 for one periodic test and synchronization is to the 4.16 kV ESS bus for Unit 1 for the next periodic test. However, if it is not possible to perform the test on Unit 1 or test performance is not required per SR 3.8.2.1, then the test shall be performed synchronized to the 4.16 kV ESS bus for Unit 2. --- Verify each DG is synchronized and loaded and operates for ≥ 60 minutes at a load ≥ 3600 kW and ≤ 4000 kW.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.4	Verify each engine mounted day tank fuel oil level is ≥ 420 gallons for DG A-D and ≥ 425 gallons for DG E.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.5	Check for and remove accumulated water from each engine mounted day tank.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.6	Verify the fuel oil transfer system operates to automatically transfer fuel oil from the storage tanks to each engine mounted tank.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.7	---------------------------NOTES--------------------------- 1. All DG starts may be preceded by an engine prelube period. 2. A single test at the specified Frequency will satisfy this Surveillance for both units. --- Verify each DG starts from standby condition and achieves, in ≤ 10 seconds, voltage ≥ 3793 V and frequency ≥ 58.8, and after steady state conditions are reached, maintains voltage ≥ ~~3793~~ 4000 V and ≤ 4400 V and frequency ≥ ~~58.8~~59.3 Hz and ≤ ~~61.2~~60.5 Hz.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.8	-----------------------------NOTE----------------------------- The automatic transfer of unit power supply shall not be performed in MODE 1 or 2. --- Verify automatic and manual transfer of unit power supply from the normal offsite circuit to the alternate offsite circuit.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.1.9	----------NOTE---------- A single test at the specified Frequency will satisfy this Surveillance for both units. -------------------- Verify each DG rejects a load greater than or equal to its associated single largest post-accident load, and: a. Following load rejection, the frequency is ≤ 64.5 Hz; b. Within 4.5 seconds following load rejection, the voltage is ≥ 3760 V and ≤ 4560 V, and after steady state conditions are reached, maintains voltage ≥ ~~3793~~ 4000 V and ≤ 4400 V; and c. Within 6 seconds following load rejection, the frequency is ≥ ~~58.8~~59.3 Hz and ≤ ~~61.2~~60.5 Hz.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.10 .	----------NOTE---------- A single test at the specified Frequency will satisfy this Surveillance for both units. -------------------- Verify each DG does not trip and voltage is maintained ≤ 4560 V during and following a load rejection of ≥ 4000 kW.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.11	------------------------------NOTES------------------------------ 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not be performed in MODE 1, 2 or 3. 3. This SR shall be performed for each DG on a rotational test basis and for each 4.16 kV ESS bus at the specified FREQUENCY. -- Verify on an actual or simulated loss of offsite power signal: a. De-energization of 4.16 kV ESS buses; b. Load shedding from 4.16 kV ESS buses; and c. DG auto-starts from standby condition and: 1. energizes permanently connected loads in ≤ 10 seconds, 2. energizes auto-connected shutdown loads through individual load timers, 3. maintains steady state voltage ≥ ~~3793~~ 4000 V and ≤ 4400 V, 4. maintains steady state frequency ≥ ~~58.8~~59.3 Hz and ≤ ~~61.2~~60.5 Hz, and 5. supplies permanently connected loads for ≥ 5 minutes.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.12	---------------------------NOTES--------------------------- 1. All DG starts may be preceded by an engine prelube period. 2. DG E, when not aligned to the Class 1E distribution system, may satisfy this SR for both units by performance of SR 3.8.1.12.a, b and c using the test facility to simulate a 4.16 kV ESS bus. SR 3.8.1.12.d and e may be satisfied with either the normally aligned DG or DG E aligned to the Class 1E distribution system. --- Verify, on an actual or simulated Emergency Core Cooling System (ECCS) initiation signal, each DG auto-starts from standby condition and: a. In ≤ 10 seconds after auto-start achieves voltage ≥ 3793 V, and after steady state conditions are reached, maintains voltage ≥ ~~3793~~ 4000 V and ≤ 4400 V; b. In ≤ 10 seconds after auto-start achieves frequency ≥ 58.8 Hz, and after steady state conditions are reached, maintains frequency ≥ ~~58.8~~59.3 Hz and ≤ ~~61.2~~60.5 Hz; c. Operates for ≥ 5 minutes; d. Permanently connected loads remain energized from the offsite power system; and e. Emergency loads are energized or auto-connected through the individual load timers from the offsite power system.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.13	---------------------------NOTES--------------------------- 1. A single test at the specified Frequency will satisfy this Surveillance for both units. 2. DG E when not aligned to the Class 1E distribution system may satisfy this SR by using a simulated ECCS initiation signal. --- Verify each DG's automatic trips are bypassed on actual or simulated loss of voltage signal on the 4.16 kV ESS bus concurrent with an actual or simulated ECCS initiation signal except: a. Engine overspeed; and b. Generator differential current; and c. Low lube oil pressure.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.1.14	---------------------------NOTES--------------------------- 1. Momentary transients outside the load ranges do not invalidate this test. 2. A single test at the specified Frequency will satisfy this Surveillance for both units. 3. DG E when not aligned to the Class 1E distribution system may satisfy this SR using the test facility. --- Verify each DG operates for ≥ 24 hours: a. For ≥ 2 hours loaded ≥ 4400 kW and ≤ 4700 kW for DGs A through D and ≥ 5000 kW and ≤ 5500 kW for DG E; and b. For the remaining hours of the test loaded ≥ 3600 kW and ≤ 4000 kW for DGs A through D and ≥ 4500 kW and ≤ 5000 kW for DG E.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.15	-----------------------------NOTES---------------------------- 1. This Surveillance shall be performed within 5 minutes of shutting down the DG after the DG has operated ≥ 2 hours loaded ≥ 3800 kW. Momentary transients outside of load range do not invalidate this test. 2. All DG starts may be preceded by an engine prelube period. 3. A single test at the specified Frequency will satisfy this Surveillance for both units. --- Verify each DG starts and achieves, in ≤ 10 seconds, voltage ≥ 3793 V and frequency ≥ 58.8 and after steady state conditions are reached, maintains voltage ≥ ~~3793~~ 4000 V and ≤ 4400 V and frequency ≥ ~~58.8~~59.3 Hz and ≤ ~~61.2~~60.5 Hz.	 In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.1.16	----------NOTE---------- This SR shall be performed for each DG on a rotational basis and for each 4.16 kV ESS bus at the specified FREQUENCY. -------------------- Verify each DG: a. Synchronizes with offsite power source while loaded with emergency loads upon a simulated restoration of offsite power; b. Transfers loads to offsite power source; and c. Returns to ready-to-load operation.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.1.17	-----------------------------NOTES---------------------------- This SR shall be performed for each DG on a rotational basis and for each 4.16 kV ESS bus at the specified FREQUENCY. --- Verify with a DG operating in test mode and connected to its bus, an actual or simulated ECCS initiation signal overrides the test mode by: a. Returning DG to ready-to-load operation; and b. Automatically energizing the emergency load from offsite power.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.18	-----------------------------NOTE----------------------------- Load timers associated with equipment that has automatic initiation capability disabled are not required to be OPERABLE. --- Verify each sequenced load is within required limits of the design interval.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.19	---------------------------NOTES--------------------------- 1. All DG starts may be preceded by an engine prelube period. 2. This SR shall be performed for each DG on a rotational test basis and for each 4.16 kV ESS bus at the specified FREQUENCY. 3. This Surveillance shall not be performed in MODE 1, 2 or 3. ---	
	Verify on an actual or simulated loss of offsite power signal in conjunction with an actual or simulated ECCS initiation signal: a. De-energization of 4.16 kV ESS buses; b. Load shedding from emergency buses; and c. DG auto-starts from standby condition and: 1. energizes permanently connected loads in ≤ 10 seconds, 2. energizes auto-connected emergency loads through individual load timers, 3. achieves steady state voltage ≥ ~~3793~~ 4000 V and ≤ 4400 V, 4. achieves steady state frequency ≥ ~~58.8~~59.3 Hz and ≤ ~~61.2~~60.5 Hz, and 5. supplies permanently connected and auto-connected emergency loads for ≥ 5 minutes.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.20	-----NOTES----- 1. All DG starts may be preceded by an engine prelube period. 2. This SR must be met, but does not have to be performed with DG E substituted for any DG. ---------- Verify, when started simultaneously from standby condition, each DG achieves, in ≤ 10 seconds, voltage ≥ 3793 V and frequency ≥ 58.8 and after steady state conditions are reached, maintains voltage ≥ ~~3793~~ 4000 V and ≤ 4400 V and frequency ≥ ~~58.8~~59.3 Hz and ≤ ~~61.2~~60.5 Hz.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.21	-----NOTE----- When Unit 1 is in MODE 4 or 5, or moving irradiated fuel assemblies in the secondary containment, the Note to Unit 1 SR 3.8.2.1 is applicable. ---------- For required Unit 1 AC sources, the following SRs of Unit 1 Specification 3.8.1 are applicable: SR 3.8.1.1; SR 3.8.1.10; SR 3.8.1.3; SR 3.8.1.11; SR 3.8.1.4; SR 3.8.1.14; SR 3.8.1.5; SR 3.8.1.15; SR 3.8.1.6; SR 3.8.1.16; SR 3.8.1.7; SR 3.8.1.18; SR 3.8.1.9; SR 3.8.1.19; and SR 3.8.1.8 (when more than one Unit 1 offsite circuit is required)	In accordance with applicable SRs

Attachment 2 to PLA-7471

Technical Specification Bases Changes (Mark-Ups)
Units 1 and 2
(For Information Only)

BASES

ACTIONS (continued)

G.1

Condition G corresponds to a level of degradation in which all redundancy in the AC electrical power supplies has been lost. At this severely degraded level, any further losses in the AC electrical power system will cause a loss of function. Therefore, no additional time is justified for continued operation. The unit is required by LCO 3.0.3 to commence a controlled shutdown.

SURVEILLANCE REQUIREMENTS

The AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with 10 CFR 50, GDC 18 (Ref. 9). Periodic component tests are supplemented by extensive functional tests during refueling outages (under simulated accident conditions). The SRs for demonstrating the OPERABILITY of the DGs are in accordance with the recommendations of Regulatory Guide 1.9 (Ref. 3), and Regulatory Guide 1.137 (Ref. 11), as addressed in the FSAR.

The Safety Analysis for Unit 2 assumes the OPERABILITY of some equipment that receives power from Unit 1 AC Sources. Therefore, Surveillance requirements are established for the Unit 1 onsite Class 1E AC electrical power distribution subsystem(s) required to support Unit 2 by LCO 3.8.7, Distribution Systems—Operating. The Unit 1 SRs required to support Unit 2 are identified in the Unit 2 Technical Specifications.

Where the SRs discussed herein specify voltage and frequency tolerances, the following summary is applicable. The minimum steady state output voltage of 4000 V represents the value that will allow the degraded voltage relays to reset after actuation. This value is based on the upper value of the degraded voltage relay reset voltage of 3938 V, representing 94.68% of 4160 V, plus the worst-case voltage drop from the DG to an associated 4.16 kV switchgear bus. The specified maximum steady state output voltage of 4400 V is equal to the maximum operating voltage specified for 4000 V. It ensures that for a lightly loaded distribution system, the voltage at the terminals of 4000 V motors is no more than the maximum rated operating voltages.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

~~The minimum steady state output voltage of 3793 V is the value assumed in the degraded voltage analysis and is approximately 90% of the nominal 4160 V output voltage. This value allows for voltage drop to the terminals of 4000 V motors whose minimum operating voltage is specified as 90% or 3600 V. It also allows for voltage drops to motors and other equipment down through the 120 V level where minimum operating voltage is also usually specified as 90% of nameplate rating. The specified maximum steady state output voltage of 4400 V is equal to the~~ The minimum frequency value is derived from the recommendations found in Regulatory Guide 1.9 (Ref. 3). The allowable steady state frequency for all DGs is 60 Hz +/- 2%. DG E is also required to maintain a frequency of not less than 57 Hz during transient conditions. To provide additional margin for DG E to meet the 57 Hz criteria, the 2% margin allowed for steady state frequency is further reduced to 1%, or 0.6 Hz. This value, added to the tolerance allowed for the DG's electronic governor (0.1 Hz) provides the 59.3 Hz minimum frequency value applicable for all DGs.

The maximum frequency is derived from analysis based on an iterative approach using voltage and frequency variations of the DG to determine the maximum continuous loading on the DG such that the DG loading does not exceed its continuous rating and still performs its design function. Through a qualitative estimation and a dynamic transient simulation, the maximum frequency meeting the iterative approach is 60.5 Hz.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

~~maximum operating voltage specified for 4000 V motors. It ensures that for a lightly loaded distribution system, the voltage at the terminals of 4000 V motors is no more than the maximum rated operating voltages. The specified minimum and maximum frequencies of the DG are 58.8 Hz and 61.2 Hz, respectively. These values are equal to ± 2% of the 60 Hz nominal frequency and are derived from the recommendations found in Regulatory Guide 1.9 (Ref. 3). The lower frequency limit is necessary to support the LOCA analysis assumptions for low-pressure ECCS pump flow rates. (Reference 12)~~

The Surveillance Table has been modified by a Note, to clarify the testing requirements associated with DG E. The Note is necessary to define the intent of the Surveillance Requirements associated with the integration of DG E. Specifically, the Note defines that a DG is only considered OPERABLE and required when it is aligned to the Class 1E distribution system. For example, if DG A does not meet the requirements of a specific SR, but DG E is substituted for DG A and aligned to the Class 1E distribution system, DG E is required to be OPERABLE to satisfy the LCO requirement of 4 DGs and DG A is not required to be OPERABLE because it is not aligned to the Class 1E distribution system. This is acceptable because only 4 DGs are assumed in the event analysis. Furthermore, the Note identifies when the Surveillance Requirements, as modified by SR Notes, have been met and performed, DG E can be substituted for any other DG and declared OPERABLE after performance of two SRs, which verify switch alignment. This is acceptable because the testing regimen defined in the Surveillance Requirement Table ensures DG E is fully capable of performing all DG requirements.

SR 3.8.1.1

This SR ensures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. The breaker alignment verifies that each breaker is in its correct position to ensure that distribution buses and loads are connected to an Operable offsite power source and that appropriate independence of offsite circuits is maintained. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

ACTIONS

F.1 and F.2 (continued)

reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

G.1

Condition G corresponds to a level of degradation in which all redundancy in the AC electrical power supplies has been lost. At this severely degraded level, any further losses in the AC electrical power system will cause a loss of function. Therefore, no additional time is justified for continued operation. The unit is required by LCO 3.0.3 to commence a controlled shutdown.

SURVEILLANCE REQUIREMENTS

The AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with 10 CFR 50, GDC 18 (Ref. 9). Periodic component tests are supplemented by extensive functional tests during refueling outages (under simulated accident conditions). The SRs for demonstrating the OPERABILITY of the DGs are in accordance with the recommendations of Regulatory Guide 1.9 (Ref. 3), and Regulatory Guide 1.137 (Ref. 11), as addressed in the FSAR.

The Safety Analysis for Unit 2 assumes the OPERABILITY of some equipment that receives power from Unit 1 AC Sources. Therefore, Surveillance requirements are established for the Unit 1 onsite Class 1E AC electrical power distribution subsystem(s) required to support Unit 2 by LCO 3.8.7, Distribution Systems-Operating. As Noted at the beginning of the SRs, SR 3.8.1.1 through SR 3.8.1.20 are applicable to the Unit 2 AC sources and SR 3.8.1.21 is applicable to the Unit 1 AC sources.

~~Where the SRs discussed herein specify voltage and frequency tolerances, the following summary is applicable. The minimum steady state output voltage of 3793 V is the value assumed in the degraded voltage analysis and is approximately 90% of the nominal 4160 V output voltage. This value allows for voltage drop to the terminals of~~

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

Where the SRs discussed herein specify voltage and frequency tolerances, the following summary is applicable. The minimum steady state output voltage of 4000 V represents the value that will allow the degraded voltage relays to reset after actuation. This value is based on the upper value of the degraded voltage relay reset voltage of 3938 V, representing 94.68 % of 4160 V, plus the worst-case voltage drop from the DG to an associated 4.16 kV switchgear bus. The specified maximum steady state output voltage of 4400 V is equal to the maximum operating voltage specified for 4000 V. It ensures that for a lightly loaded distribution system, the voltage at the terminals of 4000 V motors is no more than the maximum rated operating voltages.

The minimum frequency value is derived from the recommendations found in Regulatory Guide 1.9 (Ref. 3). The allowable steady state frequency for all DGs is 60 Hz +/- 2%. DG E is also required to maintain a frequency of not less than 57 Hz during transient conditions. To provide additional margin for DG E to meet the 57 Hz criteria, the 2% margin allowed for steady state frequency is further reduced to 1%, or 0.6 Hz. This value, added to the tolerance allowed for the DG's electronic governor (0.1 Hz) provides the 59.3 Hz minimum frequency value applicable for all DGs.

The maximum frequency is derived from analysis based on an iterative approach using voltage and frequency variations of the DG to determine the maximum continuous loading on the DG such that the DG loading does not exceed its continuous rating and still performs its design function. Through a qualitative estimation and a dynamic transient simulation, the maximum frequency meeting the iterative approach is 60.5 Hz.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

~~4000 V motors whose minimum operating voltage is specified as 90% or 3600 V. It also allows for voltage drops to motors and other equipment down through the 120 V level where minimum operating voltage is also usually specified as 90% of name plate rating. The specified maximum steady state output voltage of 4400 V is equal to the maximum operating voltage specified for 4000 V motors. It ensures that for a lightly loaded distribution system, the voltage at the terminals of 4000 V motors is no more than the maximum rated operating voltages. The specified minimum and maximum frequencies of the DG are 58.8 Hz and 61.2 Hz, respectively. These values are equal to ± 2% of the 60 Hz nominal frequency and are derived from the recommendations found in Regulatory Guide 1.9 (Ref. 3). The lower Frequency Limit is necessary to support the LOCA analysis assumptions for low pressure ECCS pump flow rates. (Reference 12)~~

The Surveillance Table has been modified by a Note, to clarify the testing requirements associated with DG E. The Note is necessary to define the intent of the Surveillance Requirements associated with the integration of DG E. Specifically, the Note defines that a DG is only considered OPERABLE and required when it is aligned to the Class 1E distribution system. For example, if DG A does not meet the requirements of a specific SR, but DG E is substituted for DG A and aligned to the Class 1E distribution system, DG E is required to be OPERABLE to satisfy the LCO requirement of 4 DGs and DG A is not required to be OPERABLE because it is not aligned to the Class 1E distribution system. This is acceptable because only 4 DGs are assumed in the event analysis. Furthermore, the Note identifies when the Surveillance Requirements, as modified by SR Notes, have been met and performed, DG E can be substituted for any other DG and declared OPERABLE after performance of two SRs which verify switch alignment. This is acceptable because the testing regimen defined in the Surveillance Requirement Table ensures DG E is fully capable of performing all DG requirements.

SR 3.8.1.1

This SR ensures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. The breaker alignment verifies that each breaker is in its

(continued)

Attachment 3 to PLA-7471

Excerpts of Referenced Calculations

(For Information Only)

Including sections:

3-1 DG Steady State Output Voltage for Surveillance Tests -
Excerpts of Calculation EC-024-1031 – (15 pages)

3-2 DG Steady State Frequency Limits for DG Surveillances and RG 1.9
Excerpts of Calculation EC-024-1014 – (50 pages)

3-3 Evaluation of the Impact of DG Steady State Frequency and Voltage Variations Within Acceptable Limits,
Excerpts of Calculation EC-024-1035 – (66 pages)

Section 3-1 of Attachment 3
PLA-7471

DG Steady State Output Voltage for Surveillance Tests

(For Information Only)

Excerpts of Calculation EC-024-1031
(15 pages follow)

TECHNICAL CHANGE SUMMARY PAGE
NEPM-QA-0221-5

Calculation: Number: EC-024-1031 **Revision No.** 1

This form shall be used to (1) record the Technical Scope of the revision and (2) record the scope of verification if the calculation was verified. It should not be more than one page. Its purpose is to provide summary information to the reviewer, verifier, approver, and acceptor about the technical purpose of the change. For non-technical revisions, state the purpose or reason for the revision.

Scope of Revision:

Revised the calculation to provide the design bases for the steady state voltage limits used in the surveillances for the Diesel Generators.

Scope of Verification (If verification applies):

The scope of verification is limited to the changes made by this revision only.

1.0 Purpose

The purpose of this calculation is to determine the minimum and maximum Diesel Generator (DG) steady state output voltages for use in the DG surveillances as delineated in the Unit 1 & 2 Technical Specifications (TS) surveillance requirements in section 3.8.1.

Acceptance criteria

The minimum DG steady state output voltage used in the applicable surveillances should be above the minimum required steady state equipment voltages and above the degraded voltage relay (DVR) reset voltage for the 4.16 kV Engineered Safeguard System (ESS) Buses.

The maximum DG steady state output voltage used in the applicable surveillances should not exceed the maximum steady state equipment voltage.

2.0 Conclusions

A minimum steady state value of 4000 VAC and a maximum steady state value of 4400 VAC meets the acceptance criteria and is the acceptable limits for use in the DG surveillance procedures.

The Diesel Generators are designed to operate under two modes of operation, emergency or test mode.

In the emergency mode for the DG, the Static Exciter Voltage Regulator (SEVR) maintains a constant generator output voltage at a nominal 4250 volts that is controlled through the diesel's Power Driven Potentiometer PDP-4 (with a range from 4150 to 4350 volts). If the measured generator output voltage is different from the nominal setpoint of 4250 volts, the regulator will respond by varying the field current to correct the voltage to 4250 volts. The only time voltage is manually adjusted in the emergency mode is if the key locked bypass switch (43SYN) is used. The purpose of the 43SYN switch is to allow manual adjustment of the voltage for synchronization with offsite sources.

When the DG is operating in the test mode, the operator has the ability to manually adjust the voltage output of the DG. This occurs as part of the synchronizing process to effectively match the output voltage of the DG with the voltage of the offsite source for parallel operation. Once the DG is connected to the grid, the SEVR will allow the voltage of the DG to follow (swing) with the established voltage of the grid. This allows the DG to share loads with other paralleled generators on the grid. The grid voltage is tightly controlled by the regional transmission authority (PJM) and is very stable. If, at any time, the grid begins to behave erratically, manual disconnection of the DGs from the grid will occur. In the event of an emergent mode initiation of the DG, the DG will automatically disconnect from the grid and the output voltage of the DG will be adjusted to a voltage determined by the PDP-4 setpoint (nominal 4250 volts) and be regulated thru the SEVR.

1

As such, the minimum voltage limit of 4000 volts, as well as the maximum voltage limit of 4400 volts will be maintained by the Diesels Generators.

3.0 Inputs

3.1 Upper value of degraded grid relay reset voltage 3938.8 volts per EC-004-1031.
3.2 DG A-D continuous rating 4000 KW at 0.8pf per FSAR.
3.3 DG-E continuous rating 5000 KW at 0.8pf per FSAR.
3.4 Cable impedances from PPL ETAP library etaplib5.lib at 90 degrees C. The library values are from EC-004-1034 with temperature correction to 90 degrees C.
3.5 Deleted
3.6 For the purposes of this calculation, due to the conservatisms of this calculation and the balanced nature of a large percentage of the DG loads, it is reasonable to consider the DG to have balanced loads

4.0 Method

4.1 Method Overview for Maximum Voltage

The method used in determining the maximum steady state output voltage is derived from the lowest value of the maximum operating voltage of equipment connected to the 4 kV ESS buses. With the exception of the ESS transformers, all loads from the 4 kV buses are motor loads. The rated (terminal) voltage of the motors is 4000 volts. Per NEMA MG-1 standard, motors are designed with a 10% tolerance for voltage above and below the rated value. This equates to a maximum steady state voltage of 4400 volts.

The selection of this value, 4400 volts, also ensures that under a lightly loaded distribution system, the voltage specified at the terminals of the 4000 volt motors will not be more than the maximum rated operating voltage of 4400 volts.

4.2 Method Overview for Minimum Voltage

The minimum steady state voltage for the DGs was established based on the operation of the degraded grid voltages. SSES utilizes multiple levels of undervoltage relays (four in total) to detect degradation of the AC voltage on the 4.16 kV ESS buses. Two of the four relays, 27B1 and 27B2, are used to detect a sustained degraded voltage condition on the 4.16 kV bus and are identified as the degraded voltage relays (DVRs). The DVRs are set to drop-out at 93% of the rated bus voltage (4160 V). With each relay comes a tolerance, that when taken into account, provides the lowest expected setting of the DVR and is equivalent to 91.2% of nominal 4.16 kV bus voltage or 3793 volts.

The degraded grid voltage protection scheme sheds all non-permanently connected loads on the 4.16 kV ESS bus and opens the offsite power breakers to the subject bus when actuated. If the DG supplies voltage to the bus at the lower steady state limit of

3793 V, the DVRs will not reset and the load shed signal will remain thus preventing emergency equipment from loading onto the bus. To allow the reset of the 4160 V degraded grid protection logic, the DG's minimum steady state voltage should be increased above the upper value of the DVR reset voltage of 94.68% of the 4.16 kV bus or 3938 V. (Input 3.1)

The method used in determining the DG's minimum steady state voltage is by looking at the worst case voltage drop from the Diesel Generator to an associated 4 KV switchgear bus. This worst case voltage drop is then added to the upper value of the degraded grid relay reset voltage of 3938 volts (Input 3.1). This method is used because the degraded grid voltage is at the 4KV bus and the surveillance voltage value is based on the DG output voltage. A voltage value equal to or above this summed value is selected. This establishes a steady state DG voltage that would not result in actuation of the degraded grid relay scheme. The selected value is then evaluated to ensure that it is compatible with other setting values to which it might be related. Determining the worst case voltage drop requires determining the worst case cable impedance between the Diesel Generator and the 4KV bus and determining the maximum steady state current. This allows calculation of the associated voltage drop and of the required DG voltage to meet the acceptance criteria. 1

4.2.1 Worst case cable impedance

Figures 1 through 4 illustrate cable types and lengths for the situation where DG-E is substituted for DG-A through D respectively. Figure 5 provides a typical and more comprehensive illustration showing when DG-E is not substituted and DG-A is aligned to the 4KV bus.

Referring to Figure 5, when DG-E is not substituted, the cable lengths shown from DG-E to 0A510A02 are replaced by DG-A cables AF0G2401F and G (F10's) at 49 ft each and AF0G2401 J and H at 114 ft each (H01's). These cables add up to less impedance compared to using the cables when DG-E is substituted. A review of Table 1 for the analogous cables for DG-B, C, and D shows that in all cases, as expected, the lengths when DG-E is substituted are greater than when DG-E is not substituted, and the corresponding circuit impedance is greater with DG-E substituted.

Also, in all cases the cable length to the 4KV buses for Unit 2 is greater than that to the 4KV buses for Unit 1. Total lengths are based upon 4KV buses for Unit 2 and it is conservatively assumed that all current from each DG is supplied to its 4KV bus for Unit 2. This provides the worst case voltage drop for each case.

The worst case cable lengths are for DG-E substituted for A, and DG-E substituted for D.

The worst case impedance can be determined as follows:

From ETAP library etaplib5.lib at 90 degrees C

Material	Cable Code	R/1000 ft	X/1000 ft
Cu	H01	0.022	0.089
Al	F10	0.025	0.0341

DG-E for A		Length*R/2000 (Note 1)	Length*X/2000 (Note 1)
Length H01	780	0.00858	0.03471
Length F10	615	0.007688	0.010486
Total R and X		0.016268	0.045196
Total Z (SQRT(R^2+X^2))	0.048035	Angle 70.18 degrees	

DG-E for D		Length*R/2000 (Note 1)	Length*X/2000 (Note 1)
Length H01	810	0.00891	0.036045
Length F10	552	0.0069	0.009412
Total R and X		0.01581	0.045457
Total Z (SQRT(R^2+X^2))	0.048128	Angle 70.82 degrees	

Note 1: Note that all conductors are doubled up, cutting the effective resistance in half. This is why the devisor is 2000 and not 1000. Where the paralleled cable lengths are different, the longer length is conservatively used.

To determine which case represents the worst voltage drop will require determining the voltage drop for each case.

4.2.2 Maximum steady state current

It is appropriate to base the maximum steady state current on the DG-A through D rating rather than the higher rating of DG-E. This is because steady state loads must stay within the capability of the lower machine rating.

The highest DG load shown in the FSAR diesel loading tables is in FSAR table 8.3-3 which shows a maximum steady state diesel load of 3976.85 KW (DG-A). This is close to the 4000 KW machine nominal rating. For purposes of determining the maximum steady state current, a steady state loading of 4000 KW will be used. Using a power factor of 0.8 from the FSAR yields a KVA of 4000/0.8 = 5000 KVA.

Amps =KVA*1000/ (4160*SQRT 3) =

5000*1000/ (4160*SQRT 3) =694.75 amps. Round to 695 amps

Maximum steady state current = 695 amps

4.2.3 Voltage Drop

Since the machine rating of 5000 KVA and 4000 KW uses a 0.8 power factor, the voltage drop calculation will also use that power factor. Per input 3.6, the calculation is based on balanced loads.

The following formula is the approximate formula for line to neutral voltage drop:

Vdrop line to neutral = $I(R\cos\theta + X\sin\theta)$ Reference: Industrial Power Systems Handbook page 234.

The error introduced by using the approximate formula is minor, and is enveloped by the rounding of values in the subsequent section, "Determination of surveillance voltage."

Vdrop DG-E substituted for DG-A:

Vdrop line to neutral = 695*((0.016268*0.8) + (0.045196*0.6)) = 27.89 volts

Vdrop= line to line = (SQRT(3))* Vdrop line to neutral = 48.3 volts

Vdrop DG-E substituted for DG-D:

Vdrop line to neutral = 695*((0.01581*0.8) + (0.045457*0.6)) = 27.74 volts

Vdrop= line to line = (SQRT(3))* Vdrop line to neutral = 48.1 volts

DG-E substituted for A is the worst case voltage drop of 48.3 volts

4.2.4 Determination of surveillance voltage

The principle used was that the DG steady state output voltages used in the applicable surveillances should be above minimum required equipment voltages (part of the existing Tech Spec bases) and be above the upper end of the degraded grid relay reset value.

The diesel surveillance measures DG output voltage. The degraded grid relays monitor voltage at the 4KV bus. Therefore, the value chosen as the minimum acceptable DG steady state voltage needs to consider:

(1) The upper end of the degraded grid relay reset value (3938.8 volts) (Input 3.1)
(2) The voltage drop from the DG to the 4 KV bus (48.3 volts) (Calculated in 4.4)
(3) Any unacceptable potential interactions with other settings. (None on basis of the principle for the surveillance test that voltages be above degraded grid reset value.)

Rounding voltages yield the following:

3940 volts + 50 volts = 3990 volts.

Per discussion with System Engineers R. Bogar and L. Casella, this is rounded to 4000 volts.

4.2.5 Potential Interaction with other settings

Other settings provided by relay and test, S. Brylinsky:

PDP-4	DG VR Emergency Setpoints	4150 – 4350

Reference: Procedure MT-RC-063

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This setting indicated that the DG voltage regulator will control voltage to a minimum value of 4150 volts which is above the proposed surveillance voltage. As such, these settings would not prevent the surveillance from being successful.

27-1&2 Permissive to Close Diesel Breaker 3945 – 4106

Reference : Calculation EC-SOPC-0607 Rev. 0 applies. The associated RSCN's 82-663, -664, -665, and – 666 specify 115 V for relay pick-up. MT-RC-026, Rev. 6 specifies a tolerance of +/- 2% which is 2.3 volts. The values shown above are the corresponding DG voltage levels. (The potential transformer is 102 V to 4200V. For ex. (115+2.3)*4200/120 = 4106)

5.0 Results

A minimum steady state value of 4000 VAC and a maximum steady state value of 4400 VAC as determined in section 4.0, meets the acceptance criteria of section 1.0. These voltage values shall be the acceptable limits for use in the DG surveillances as shown in the Unit 1 & 2 Technical Specifications surveillance requirements in section 3.8.1.

6.0 References

6.1 CR 1302829, DG ISOCHONOUS SURVEILLANCE LOW VOLTAGE ACCEPTANCE CRITERIA IS NOT TECHNICALLY SUPPORTABLE

6.2 CRA 1312458, CR 1302829 PROCEDURES REQUIRING EXPEDITIOUS REVISION AND REQUIRED VOLTAGE VALUE

6.3 AR-EWR 1315923, CREATE A FORMAL CALCULATION FOR THE 4000 V CRITERION ESTABLISHED VIA CRA 1312458

6.4 CR 1315904, THE POTENTIAL EXISTS FOR THE SETPOINT FOR THE EDG BREAKER CLOSURE VOLTAGE PERMISSIVE RELAYS TO BE SET AT A HIGHER VALUE THAN THE UPPER VALUE ALLOWED FOR THE AUTO VOLTAGE REGULATOR (AVR) WHEN AN EDG IS FUNCTIONING IN EMERGENCY MODE.

6.5 EC-004-1031, Rev. 4, PLANT AC LOADFLOW ANALYSIS

6.6 CRIMP

6.7 ETAP library etaplib5.lib

6.8 EC-004-1034, Rev. 1, POWER CABLE DATA FOR ETAP

6.9 Industrial Power Systems Handbook, Donald Beeman, McGraw-Hill, 1955

6.10 FSAR text 8.3.1.4, Rev. 68 in NIMS

6.11 FSAR table 8.3-3 Table Rev 56 in NIMS

6.12 Schematic drawing E-23, Sheet 6, Rev. 28

6.13 Schematic drawing E-23, Sheet 6B, Rev. 2

6.14 Schematic drawing E-23, Sheet 6C, Rev. 7

6.15 Schematic drawing E-23, Sheet 6D, Rev. 2

6.16 Schematic drawing E-23, Sheet 6E, Rev. 10

6.17 Schematic drawing E-23, Sheet 6F, Rev. 2

6.18 Schematic drawing E-23, Sheet 6G, Rev. 9

6.19 Schematic drawing E-23, Sheet 6H, Rev. 2

6.20 Schematic drawing E-23, Sheet 10, Rev. 10

6.21 Schematic drawing E-23, Sheet 13, Rev. 9

6.22 Procedure MT-RC-026, Rev. 6, CS (POT. & BRUM.) RELAY CALIBRATION PROCEDURE

6.23 RSCN's 82-663 through 666

6.24 EC-SOPC-0607, Rev. 0, RELAY SETTING CALCULATION FOR DIESEL GENERATOR A&B&C&D&E VOLTAGE PERMISSIVE FOR LOADING SUPERSEDES 1-20204-13 REV 1

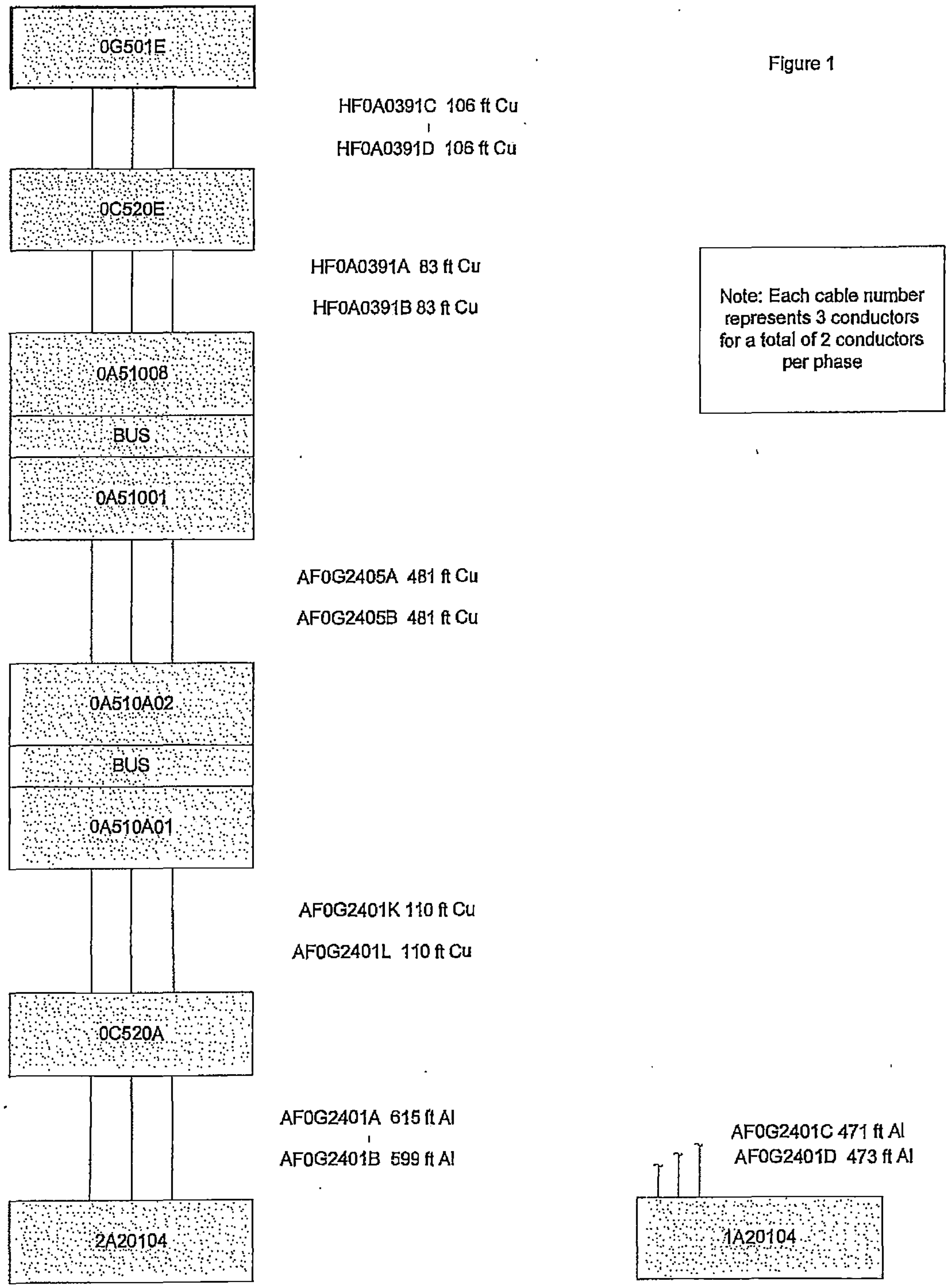
6.25 MT-RC-063, Rev. 2, STANDBY DIESEL GENERATOR AUTO VOLTAGE REGULATOR POWER DRIVEN POTENTIOMETER ADJUSTMENT PROCEDURE

6.26 Unit 1 Technical Specification Bases 3.8.1, Rev. 7

6.27 Unit 2 Technical Specification Bases 3.8.1, Rev. 9

1

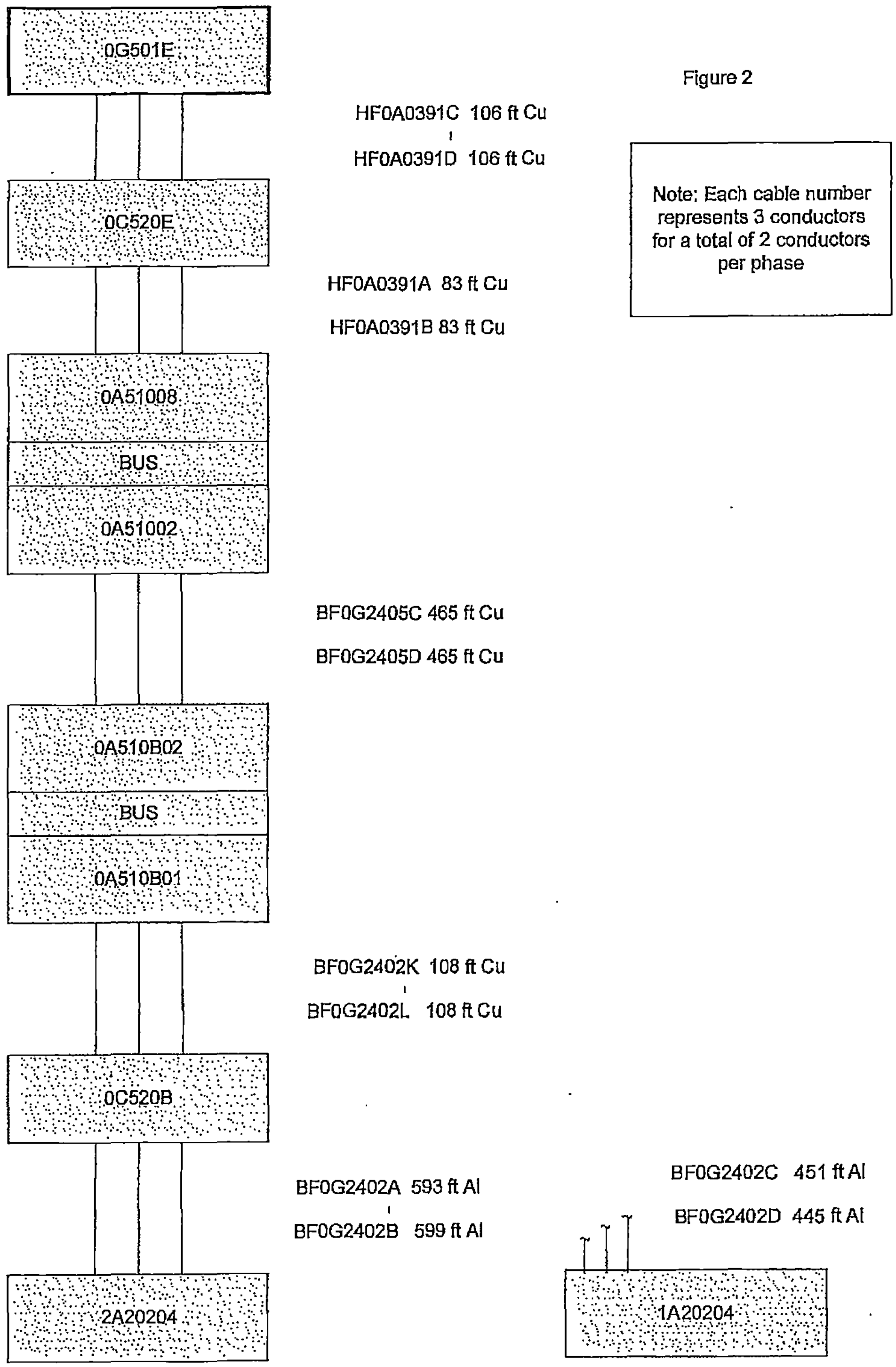
Figure 1



Cu is cable code H01. Total H01 length is 780 ft for any one conductor path

Al is cable code F10. Total F10 length is 615 ft for any one conductor path

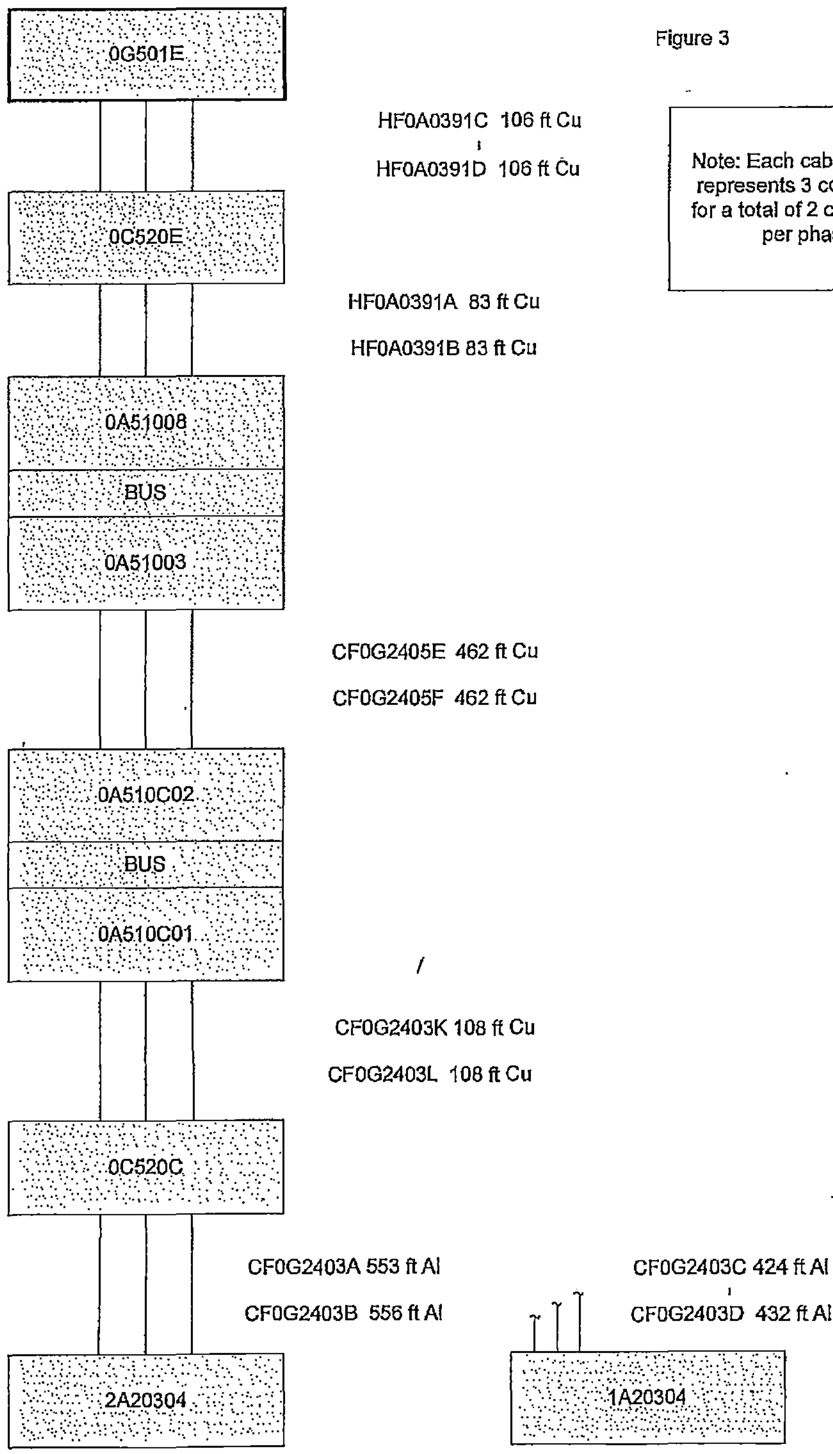
Figure 2



Cu is cable code H01. Total H01 length is 762 ft for any one conductor path

Al is cable code F10. Total F10 length is 599 ft for any one conductor path

Figure 3

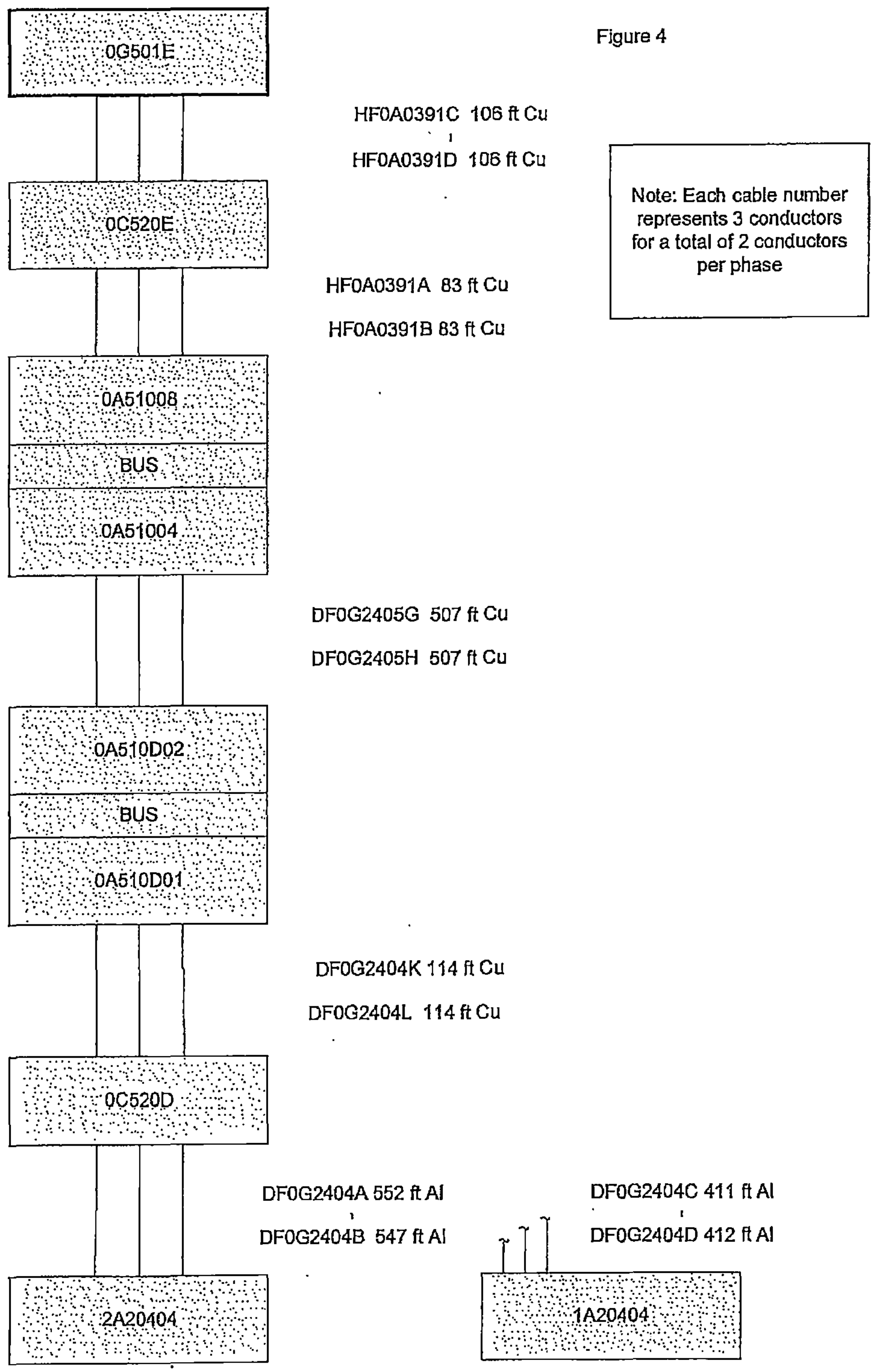


Note: Each cable number represents 3 conductors for a total of 2 conductors per phase

Cu is cable code H01. Total H01 length is 759 ft for any one conductor path

Al is cable code F10. Total F10 length is 556 ft for any one conductor path

Figure 4



Cu is cable code H01. Total H01 length is 810 ft for any one conductor path

Al is cable code F10. Total F10 length is 552 ft for any one conductor path

Figure 5

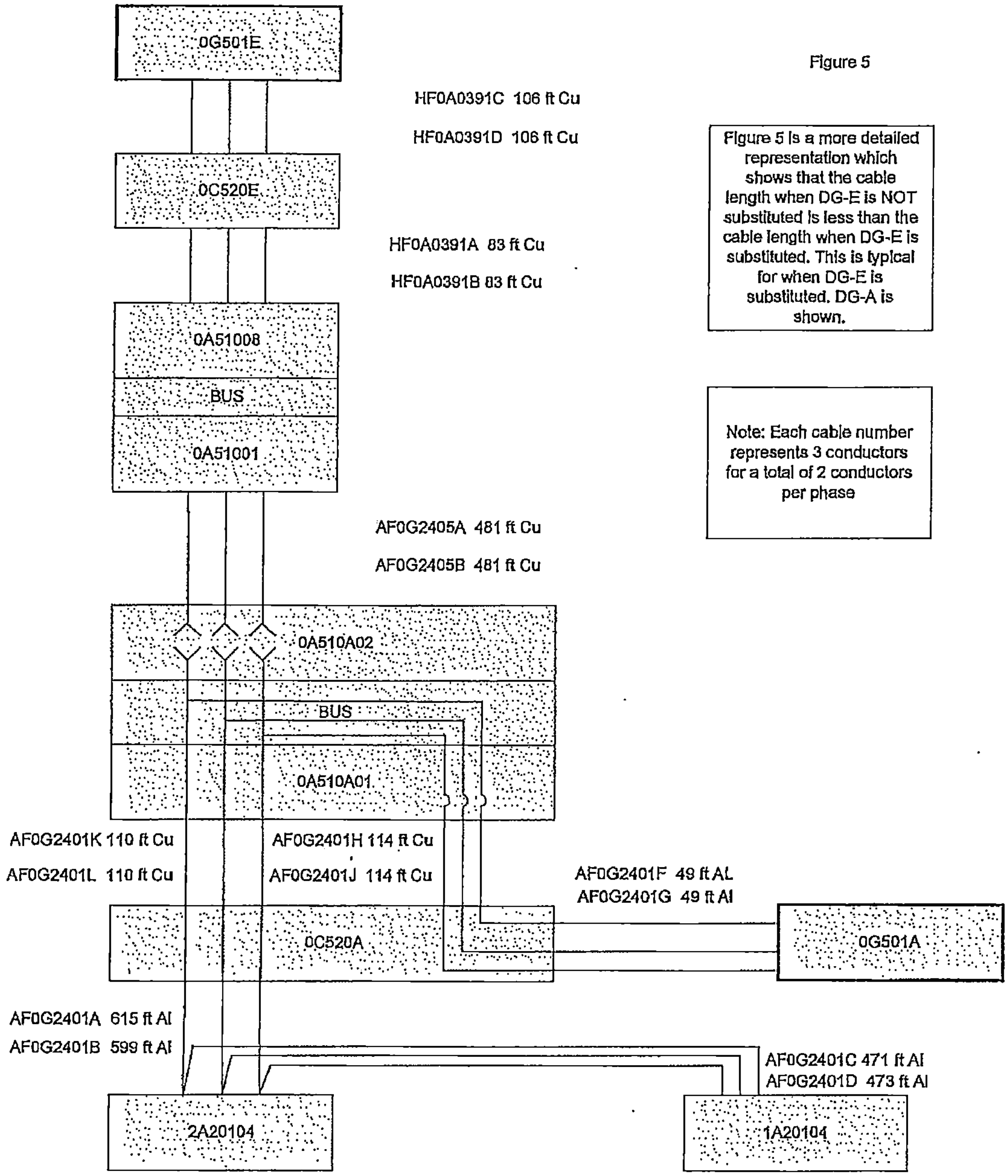


Figure 5 is a more detailed representation which shows that the cable length when DG-E is NOT substituted is less than the cable length when DG-E is substituted. This is typical for when DG-E is substituted. DG-A is shown.

Note: Each cable number represents 3 conductors for a total of 2 conductors per phase

Cu is cable code H01.

Al is cable code F10.

Table 1

```
SELECT TRAK2000_CABL.ID, TRAK2000_CABL.FROMEQ, TRAK2000_CABL.TOEQ,
TRAK2000_CABL.CODE, TRAK2000_CABL.ILEN, TRAK2000_CABL.DLEN
FROM TRAK2000_CABL
WHERE (((TRAK2000_CABL.ID) Like "?F0G240[1-4]?" Or (TRAK2000_CABL.ID) Like
"?F0G2405[A-H]")) OR (((TRAK2000_CABL.ID) Like "HF0A0391[A-D]"))
ORDER BY TRAK2000_CABL.ID;
```

ID	FROMEQ	TOEQ	CODE	ILEN	DLEN
AF0G2401A	0C520A	2A20104	F10	615	615
AF0G2401B	0C520A	2A20104	F10	599	599
AF0G2401C	0C520A	1A20104	F10	471	471
AF0G2401D	0C520A	1A20104	F10	473	473
AF0G2401E	0C520A	0G501A	F04	49	49
AF0G2401F	0C520A	0G501A	F10	49	49
AF0G2401G	0C520A	0G501A	F10	49	49
AF0G2401H	0A510A01	0C520A	H01	114	114
AF0G2401J	0A510A01	0C520A	H01	114	114
AF0G2401K	0A510A01	0C520A	H01	110	110
AF0G2401L	0A510A01	0C520A	H01	110	110
AF0G2405A	0A510A02	0A51001	H01	481	481
AF0G2405B	0A510A02	0A51001	H01	481	481
BF0G2402A	0C520B	2A20204	F10	593	593
BF0G2402B	0C520B	2A20204	F10	599	599
BF0G2402C	0C520B	1A20204	F10	451	451
BF0G2402D	0C520B	1A20204	F10	445	445
BF0G2402E	0C520B	0G501B	F04	49	49
BF0G2402F	0C520B	0G501B	F10	49	49
BF0G2402G	0C520B	0G501B	F10	49	49
BF0G2402H	0A510B01	0C520B	H01	113	113
BF0G2402J	0A510B01	0C520B	H01	113	113
BF0G2402K	0A510B01	0C520B	H01	108	108
BF0G2402L	0A510B01	0C520B	H01	108	108
BF0G2405C	0A510B02	0A51002	H01	465	465
BF0G2405D	0A510B02	0A51002	H01	465	465
CF0G2403A	0C520C	2A20304	F10	553	553
CF0G2403B	0C520C	2A20304	F10	556	556
CF0G2403C	0C520C	1A20304	F10	424	424
CF0G2403D	0C520C	1A20304	F10	432	432
CF0G2403E	0C520C	0G501C	F04	35	35

ID	FROMEQ	TOEQ	CODE	ILEN	DLEN
CF0G2403F	0C520C	0G501C	F10	35	35
CF0G2403G	0C520C	0G501C	F10	35	35
CF0G2403H	0A510C01	0C520C	H01	112	112
CF0G2403J	0A510C01	0C520C	H01	112	112
CF0G2403K	0A510C01	0C520C	H01	108	108
CF0G2403L	0A510C01	0C520C	H01	108	108
CF0G2405E	0A510C02	0A51003	H01	462	462
CF0G2405F	0A510C02	0A51003	H01	462	462
DF0G2404A	0C520D	2A20404	F10	552	552
DF0G2404B	0C520D	2A20404	F10	547	547
DF0G2404C	0C520D	1A20404	F10	411	411
DF0G2404D	0C520D	1A20404	F10	412	412
DF0G2404E	0C520D	0G501D	F04	34	34
DF0G2404F	0C520D	0G501D	F10	34	34
DF0G2404G	0C520D	0G501D	F10	34	34
DF0G2404H	0A510D01	0C520D	H01	116	116
DF0G2404J	0A510D01	0C520D	H01	116	116
DF0G2404K	0A510D01	0C520D	H01	114	114
DF0G2404L	0A510D01	0C520D	H01	114	114
DF0G2405G	0A510D02	0A51004	H01	507	507
DF0G2405H	0A510D02	0A51004	H01	507	507
HF0A0391A	0A51008	0C520E-HV	H01		83
HF0A0391B	0A51008	0C520E-HV	H01		83
HF0A0391C	0C520E-HV	0G501E	H01		106
HF0A0391D	0C520E-HV	0G501E	H01		106

Use design length (DLEN) if installed length (ILEN) is blank.

Section 3-2 of Attachment 3
PLA-7471

DG Steady State Frequency Limits for DG Surveillances and RG 1.9

(For Information Only)

Excerpts of Calculation EC-024-1014
(50 pages follow)

TECHNICAL CHANGE SUMMARY PAGE
NEPM-QA-0221-5

Calculation: Number: EC-024-1014 **Revision No.** 4

This form shall be used to (1) record the Technical Scope of the revision and (2) record the scope of verification if the calculation was verified. It should not be more than one page. Its purpose is to provide summary information to the reviewer, verifier, approver, and acceptor about the technical purpose of the change. For non-technical revisions, state the purpose or reason for the revision.

Scope of Revision:

Revised the calculation to provide the design bases for the steady state frequency limits used in the surveillances for the Diesel Generators.

NOTE: Pages 3 thru 46 of revision 3 were renumbered only. No Changes occurred to these pages under this revision.

Scope of Verification (If verification applies):

The scope of verification is limited to the changes made by this revision only.

1.0 Purpose

The purpose of this calculation is twofold:

i. To determine the acceptance criterion for the Diesel Generator (DG) A thru E steady state frequency for use in the DG surveillances as delineated in the Unit 1 & 2 Technical Specifications (TS) surveillance requirements in section 3.8.1, and

ii. To demonstrate the electrical and mechanical equipment connected to the DGs are able to perform their required functions at a power supply frequency between the required values provided in Regulatory Guide 1.9 (i.e. at a frequency of 60 hertz ± 2%).

2.0 Conclusion

i. A minimum steady state frequency value of 59.3 hertz and a maximum steady state frequency value of 60.5 hertz are the acceptable limits for use in the DG surveillance procedures.

The Diesel Generators are designed to operate under two modes of operation, emergency or test mode.

In the emergency mode for the DG, the electronic governor will maintain rated speed and frequency at a constant 600 rpm or 60 hertz. The only time the frequency of the DG is manually adjusted in the emergency mode is if the key locked bypass switch (43SYN) is used. The purpose of the 43SYN switch is to allow engine speed to be manually varied for synchronization with offsite sources.

When the DG is operating in the test mode, the operator has the ability to manually adjust the speed/frequency output of the DG. The electronic governor, when placed in droop mode, will allow the speed and frequency to drop (droop) in response to increased load on the machine without returning the machine to rated speed and frequency. This allows the generator to share load with other paralleled generators (or the grid) by slowing slightly in response to increase load (torque) on the generator. The grid frequency is tightly controlled by the regional transmission authority (PJM) and is very stable at 60 hertz. If, at any time, the grid begins to behave erratically, manual disconnection of the DGs from the grid will occur. With the DG normally in the test mode, upon the receipt of an emergent mode initiation of the DG, the DG will disconnect from the grid and the governor will automatically switch to the isochronous mode and maintain rated speed and frequency.

As such, the minimum frequency limit of 59.3 hertz, as well as the maximum frequency limit of 60.5 hertz will be maintained by the Diesels Generators.

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ii. Section 6.0 of this calculation, along with attachments 1, 2 and 3, provide the detailed analysis of the impact a ± 2% change in frequency will have on equipment connected to the DG. In summary, the change in frequency will not adversely affect the equipment's capability to perform their design function to mitigate the effects of a design basis accident.

3.0 References

3.1 Unit 1 and Unit 2 Technical Specifications SR 3.8.1.7, SR 3.8.1.9, SR 3.8.1.11, SR 3.8.1.12, SR 3.8.1.15, SR 3.8.1.19 and SR 3.8.1.20.

3.2 Regulatory Guide 1.9 "Selection, Design, Qualification, and Testing of Emergency Diesel Generator Units Used as Class 1E Onsite Electrical Power Systems at Nuclear Power Plants"

3.3 E54, E57 and E119A – Purchase Specifications for Vital AC, Computer UPS and Battery Chargers

3.4 E112 – Purchase Specification for Induction Motors

3.5 E117 – Purchase Specification for Load Centers

3.6 NEMA Standard MG-2-1977, "Safety Standard for Construction and Guide for Selection, Installation and Use of Electric Motors and Generators"

3.7 IEEE/ANSI Standard C57.12.01-1987, "Standard General Requirements for Dry Type Distribution and Power Transformers Including Those with Solid Cast and/or Resin Encapsulated Windings"

3.8 PL-NF-98-007(P), "Susquehanna SES Measurement Uncertainties in Appendix K LOCA Analyses"

3.9 Deleted

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4.0 Inputs and Assumptions

4.1 Momentary frequency transients during changes in diesel loading are not considered in this study.

4.2 Standards and specifications for some equipment types do not have explicit information pertaining to continuous operation at power frequencies other than 60 hertz. For those cases, this study uses engineering judgment and qualitative reasoning to evaluate equipment performance with a ± 2% frequency variation.

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5.0 Method

FSAR section 8.1.6 identifies the NRC Regulatory Guides (RG) and IEEE Standards for the Diesel Generator performance. In Sections 8.1.6.1b (for DG A thru D) & 8.1.6.1c (for

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DG E), SSES commits to Regulatory Guide 1.9 requirements of the Diesel Generator's steady state frequency of being within 2% of nominal 60 hertz (58.8 to 61.2 hertz).

However, Diesel Generator E is committed to revision 2 of RG 1.9. This revision requires the frequency of the DG, during transient periods, cannot fall below 95% of nominal frequency or 57 hertz. Diesel Generators A thru D are committed to RG 1.9 revision 0 which takes exception to the 57 hertz minimum frequency requirement during transient conditions. During previous LOCA/LOOP surveillances, the maximum frequency dip observed on the DGs was 2 hertz during the transient period of the RHR pump motor start. If the DG E was operating at its lower allowable steady state limit of 58.8 hertz, this would equate to a transient frequency of 56.8 hertz, below the committed 57 hertz.

To ensure the DG E does not dip below the 57 hertz requirement, the allowable limit for the steady state frequency, for all DG A thru E, shall be tightened from the existing limit of 60 hertz ± 2% (58.8 to 61.2 hertz) as currently provided under RG 1.9, to a new limit as determined below.

5.1 Minimum Steady State Frequency

In accordance with procedure IC-024-001A thru E, the tuning of the DG electronic governor shall be set for a frequency of 60 ± 0.1 hertz. This allows for a minimum setting of the DG of 59.9 hertz. RG 1.9 allows for a ± 2% margin for DG's steady state frequency. To provide additional margin necessary for DG-E to avoid dipping below the 57 hertz under transient conditions, the 2% margin allowed for steady state frequency shall be reduced to 1% or 0.6 hertz. With the lowest frequency allowed by the DG electronic governor (59.9 hertz), the minimum steady state frequency for the DG is 59.3 hertz (59.9 – 0.6 hertz).

5.2 Maximum Steady State Frequency

The setpoint for maximum frequency is based on an iterative approach, using voltage and frequency variations of the DG to determine the maximum continuous loading on the DG such that the DG loading does not exceed its continuous rating of 4000 kW for DG A thru D and 5000 kW for DG E. Also considered during the analysis was the effects the frequency and voltage variations would have on the DG's auxiliary equipment and various safety related equipment; and its impact not to adversely affect their capability to perform their design function to mitigate the effects of a design basis accident. This analysis is performed as part of calculation EC-024-1035. Thru a qualitative estimation and a dynamic transient simulation performed in ETAP, the maximum frequency meeting the iterative approach described above is 60.5 hertz.

5.3 Acceptance of RG 1.9

5.3.1 Identify the basic types of plant electrical equipment that are powered by the emergency diesel generators.

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5.3.2 Identify the types of mechanical equipment that are electrically driven by the emergency diesel generators

5.3.3 Describe qualitatively how the power frequency affects the performance of each type of equipment identified above.

5.3.4 Qualitatively evaluate whether a ± 2% change in diesel generator frequency is acceptable for the operation of each equipment type identified above.

6.0 Results

i. A minimum steady state frequency value of 59.3 hertz and a maximum steady state frequency value of 60.5 hertz as determined in section 5.0, shall be the acceptable limits for use in the DG surveillances.

The minimum steady state frequency limit of 59.3 hertz allows for a 2.3 hertz delta between the DG's minimum steady state frequency and the minimum transient frequency of 57 hertz as required for DG E under RG 1.9 revision 2. Previous LOCA/LOOP surveillances identified a maximum frequency dip of 2.0 hertz during the transient period of the RHR pump motor start. This new setpoint provides for an additional 0.3 hertz margin.

ii. The results provided below demonstrates that the electrical and mechanical equipment driven by the DG are capable of performing their required design functions at a steady state frequency between 58.8 and 61.2 hertz, as required under RG 1.9.

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6.1 - Heaters

The output from an electric heater depends on the root mean square (RMS) value of the supply voltage and is not affected by the supply frequency.

6.2 - Power Transformers

The minimum operating frequency for transformers is limited by magnetizing currents and core losses which depend on the volts per hertz ratio. The ANSI/IEEE standards (Reference 3.7) do not specify transformer operation at frequencies other than 60 Hz; however, decreasing frequency by 2% has the same effect on the volts per hertz ratio and core losses as increasing the supply voltage by 2%. Since transformers have a nominal voltage operating range of ±10% at 60 Hz and are loaded by design to 80% or less of their nominal KVA ratings at SSES, it is reasonable to expect these transformers are able to operate within a frequency range of 60 Hz ±2% without overheating from excessive losses within the nominal voltage operating range.

6.3 - Instrument Transformers

The above discussion for power transformers also generally applies to potential transformers (PTs), assuming that the electrical burdens are maintained below the volt-amp ratings of the PTs. For current transformers (CTs), operation at a lower frequency reduces the magnitude of the current where core saturation begins; however, since

CTs typically operate well below saturation current levels, a 2% frequency reduction has a negligible effect on the operation of these devices.

6.4 - Induction Motors *

The minimum operating frequency for induction motors is also related to the maximum allowable volts per hertz ratio which affects the magnetizing currents and losses. Decreasing the frequency by 2% has the same effect as increasing the voltage by 2% in terms of magnetizing current and losses. NEMA Standard MG-2 (Reference 3.6) allows a frequency variation of up to 5% provided that the arithmetic sum of the frequency variation and the voltage variation does not exceed 10%. This is very conservative. A 2% frequency reduction reduces the synchronous speed by 2% and causes induction motors to run 2% slower, reducing the mechanical load and the load current of the motor; therefore, the increase in magnetizing losses at the lower frequency is offset by a reduction in the load current losses at the slower speed.

The effects of a 2% speed reduction on the driven load depend on the type of mechanical load being driven. Some examples are discussed below.

- Pumps - Pump discharge pressures are reduced by approximately 4% and pump flows are reduced by approximately 2%. For ECCS pumps (LPCI and Core Spray), small reductions in performance are potentially significant to the LOCA analyses because these analyses use 60 Hz nominal pump flows and pressures near the design values of the pumps; therefore, Attachment 1 provides a detailed analysis of LPCI and Core Spray performance in terms of the LOCA analyses considering a 2% variation in the power supply frequency.

  Attachment 1 shows that a 2% variation in power supply frequency combined with errors in pressure and flow instrumentation result in total ECCS pump flow uncertainties between 5.2% and 7.4% for the various LOCA scenarios; however, this is acceptable due to the inherent conservatism of the Appendix K LOCA analysis in terms of calculating peak cladding temperatures.

- Chillers - The chiller capacity in BTU per hour is reduced by approximately 2%. This estimate is based on a standard refrigeration cycle where saturated refrigerant vapor is compressed by a positive-displacement pump to a superheated state and is then cooled through a condenser which discharges heat to the environment. Saturated liquid from the condenser is bled through a valve at a constant enthalpy to a lower pressure and temperature, and the refrigerant is then heated through an evaporator which absorbs heat from the process. If the speed of the positive-displacement pump is reduced by 2% the change in enthalpy per pound of refrigerant passing through the evaporator is essentially the same as at nominal speed; however the refrigerant flow in pounds per second is reduced by approximately 2%. Therefore, the rate of heat absorbed by the evaporator is reduced by approximately 2%.

* See Att. 3 for discussion of torque at higher frequency.

- Fans - Air flow is reduced by approximately 2%. If the fan discharges air through an electric heater, the heated air temperature is increased and the heating effect of the air remains essentially unchanged. If the fan is part of a refrigeration system, the reduction in air flow is approximately the same as the BTU/hr capacity of the chiller; hence, the chilled air temperature is essentially unchanged but the cooling effect of the air is reduced by approximately 2%.

- Motor Operated Valves - Since the speed-torque characteristic of a typical MOV induction motor at the operating point is relatively flat compared to pump or fan motors, both voltage and frequency affect motor speed for a given load torque. Reducing the frequency decreases the synchronous speed; however, this is offset by a slight increase in torque due to higher magnetizing current and magnetic flux at the higher volts per hertz ratio. Therefore, MOV stroke times are increased by somewhat less than 2%. Maintenance Technology - Valve Team prepared the following assessment of increasing MOV stroke times by 2%:

  "Increasing valve stroke times by 2% would have no adverse impact on the valve's ability to change position within its accident analysis limits (Tech Spec or FSAR). Of the 52 MOVs affected, 31 have IST limits which are at least 2% below the FSAR/Tech Spec limit thereby insuring that the accident analysis limit is not exceeded. For the remaining 21 MOVs the IST limit is the same as the FSAR/Tech Spec limit. A review of the most recent stroke times for these MOVs revealed a greater than 2% margin between the actual stroke time and the accident analysis limit hence no concern exists."

With the exception of ECCS pumps and MOVs, the effect of a 2% speed reduction on system performance is inconsequential because these systems are not typically required to operate continuously at their maximum capabilities. For example, chillers and closed cooling water systems are typically cycled or throttled. A small reduction in performance merely results in changes in the throttle settings or the on/off cycle times.

A 2% increase in the power supply frequency increases the speeds of driven loads by approximately 2%. This does not decrease the ability of these loads to perform their required functions. In general, horsepower is proportional to the cube of the speed of the driven load; therefore, a 2% increase in frequency results in approximately a 6% increase in the horsepower load on the motors. Induction motors are generally sized to equal or exceed the nominal horsepower of the driven loads. Per Reference 3.4, * induction motors at SSES were specified to have a service factor of 1.15; therefore, these motors are not overloaded for a 2% increase in frequency.

Detailed evaluations of specific safety-related plant systems and components are presented in Attachment 2 of this study.

* For RHR & Core Spray which have a S.F. of 1.0, see Attachment 3.

6.5 - Relays and Solenoid Devices

For electromechanical relays, a 2% decrease in frequency has roughly the same effect as a 2% increase in voltage, since the magnetizing current and the magnetic flux are approximately proportional to the volts per hertz ratio. For over- and under-voltage relays, reducing the frequency by 2% is therefore roughly equivalent to decreasing the voltage setpoint by 2%. Increasing the frequency by 2% is roughly equivalent to increasing the voltage setpoint by 2%. Electromechanical relays are not typically used where high precision is required.

For A.C. solenoids, a 2% reduction in frequency increases the volts per hertz ratio thereby decreasing the minimum pickup voltage. This improves the low-voltage performance of solenoids, although heating losses will increase at full voltage at the lower frequency. Conversely, a 2% increase in frequency increases the minimum pickup voltage; however, since an A.C. solenoid device is typically designed to be fail-safe, the safety function is performed by de-energizing the solenoid. Therefore, a 2% frequency variation in either direction should have no adverse consequences on the safety functions of these devices.

6.6 - Electronic Devices

Electronic voltage relays operate by measuring peak voltage values; therefore, these relays are relatively insensitive to the fundamental frequency. For relays equipped with harmonic filters, the peak voltage measurements should not be affected by a 2% change in frequency because these filters only attenuate frequencies approaching 120 Hz.

In cases where power quality (i.e., frequency, voltage, harmonics), could affect the performance of electronic devices such as instruments and computers, these devices are supplied either by D.C. power supplies or uninterruptible A.C. power supplies (UPS). A UPS rectifies the A.C. supply voltage to D.C. voltage and the D.C. voltage is then electronically inverted into a high-quality, regulated 60 Hz output. The SSES purchase specifications for Vital AC, Computer UPS and Battery Chargers (Reference 3.3) all specify an input power frequency range of 60 Hz ± 5%; therefore a 2% variation in frequency does not affect performance characteristics of these devices.

6.7 - Circuit Breakers

Thermally-operated circuit breakers are unaffected by the power frequency, since these breakers are actuated by the heating effect of the overload current on the eutectic or bimetal device that operates the breaker. The heating effect depends on the root mean square (RMS) value of the current and is not affected by the frequency.

Magnetic circuit breakers are unaffected by the power frequency, since magnetic breakers are actuated by magnetic forces produced by the overload current. These forces depend only on the magnitude of the overload current and not on the frequency.

Therefore, the tripping characteristics of circuit breakers are not affected by a ±2% frequency variation.

LPCI and Core Spray Pump Flow Uncertainty in the LOCA Analyses

The uncertainties induced by instrumentation inaccuracies during surveillance testing, as well as the uncertainty which results from the potential for a reduced emergency diesel generator speed will be estimated. Since there is an equal probability that these uncertainties could result in a conservatively high flow, it is acceptable to combine them via the Square Root of the Sum of the Squares (SRSS) method provided they are statistically independent. To allow for a comparison of the magnitude of these uncertainties, they will be described in terms of flow (GPM). In addition, where statistically allowable, the terms will be combined via the SRSS method, and then described in terms of a percentage of the total flow.

The Core Spray flow uncertainties for one loop and two loop accident scenarios will be determined. For LPCI, the flow uncertainties for the following accident cases will be determined: 1) a single pump in one loop; 2) a single pump in each loop; 3) two pumps in one loop; and 4) two pumps in two loops. Finally, the uncertainties will be determined for the most limiting Design Basis LOCA scenarios identified in Table 6.3-5 of the FSAR.

I) CORE SPRAY

a) <u>Assumptions / Inputs</u>

With respect to pump quarterly flow surveillance testing: [1a]

1) The Technical Specification surveillance requirement for a loop of Core Spray is 6350 GPM at a pump discharge pressure of 269/282 PSI for Unit 1/2.[2]

2) The overall accuracy of the flow and pressure readings obtained during quarterly pump surveillance testing is 2%.[3-5]

3) During Core Spray loop surveillance testing, the discharge pressure is read from PI-E21-1(2)R600A/B[1] or computer point NSP001/2Z, which have a full scale range of 0 - 500 PSI[6].

4) During surveillance testing, the loop flow is read from FI-E21-1(2)R601A/B[1] or NSF001/2Z which have a full scale range of 0 - 10,000 GPM[6].

5) The pump test conditions are assumed to be 75°F, which corresponds to .4324 PSI per FT of pump head[7], or 2.313 FT per PSI.

6) The points on the Core Spray\Unit 2 system flow vs. pump head curves which will be used in this evaluation are obtained from Reference 8 and are: <u>6000 GPM @ 665 FT-TDH</u>, and the test point of <u>6350 GPM @ 644 FT-TDH</u>.

With respect to emergency diesel generator diesel testing: [9-10]

7) The assumed Technical Specification surveillance requirement for steady state diesel generator speed is 60 Hz +/- 2 %, or 58.8 Hz.[11]

8) The overall accuracy of the frequency measurement during diesel generator testing is 0.5%.[8]

b) Flow Uncertainty During Pump (i.e., Loop) Testing

During testing, the actual loop flow could be less than the indication on FI-E21-1(2)R601A/B, which has a full scale range of 0 - 10,000 GPM. Per Input #2 the accuracy of the instrument is 2% of full scale. Therefore, the uncertainty induced due to flow instrumentation accuracy is:

$$\sigma_{CS,Flow} = .02 \times 10{,}000 = \underline{200\ \text{GPM}}$$

c) Discharge Pressure Uncertainty During Pump (i.e., Loop) Testing

During testing, the actual loop flow could be less than the indication on PI-E21-1(2)R600A/B, which has a full scale range of 0 - 500 PSI. Per Input #2 the accuracy of the instrument is 2% of full scale. Therefore, the actual pressure could be 10 PSI (.02 x 500) less than indicated. Per Input #5 above, this corresponds to approximately: 10 ~~PSI~~ * 2.313 FT/~~PSI~~ = 23 FT of pump head.

From Reference 8 and per Input #6 above, the slope of the Core Spray system flow vs. pump head at the test flow of 6350 GPM (3175 GPM per pump) is (6000 - 6350) / (665 - 644) = -16.7 GPM/FT. Therefore, the equivalent reduction in flow corresponding to a 23 FT reduction in head is:

$$\sigma_{CS,Press} = 16.7\ \text{GPM}/\cancel{\text{FT}} \times 23\ \cancel{\text{FT}} = \underline{384\ \text{GPM}}$$

d) Uncertainty Due To The Potential For Lower Diesel Speed

Per Input #7 above, the minimum allowable steady state diesel speed assumed for this evaluation is 60 Hz +/- 2%. In addition, as the result of instrumentation accuracies, the actual speed could be 0.5% less than the indicated reading. Since the minimum allowable speed and the measurement uncertainty are independent, as well as the fact that there is an equal probability that these factors could result in a conservatively high speed, they can be combined via the SRSS method. Therefore, the minimum expected diesel speed is:

$$\text{SPEED}_{Low} = [\,(\%_{Tolerance})^2 + (\%_{Accuracy})^2\,]^{0.5}$$

$$= [\,(2.0)^2 + (0.5)^2\,]^{0.5} = 2.06\ \%$$

Since 100% diesel speed corresponds to 60 Hz, the minimum diesel speed expressed in terms of Hertz is:

$$\text{MIN SPEED}_{Hertz} = 60 - (.0206 * 60) = 58.76\ \text{Hz}$$

Per Reference 8, and Input #6 above, the point on the Core Spray head vs. system flow curve which is verified via the Unit 2 surveillance testing is: 6350 GPM (3175 GPM per pump) @ a pump total developed head of about 644 FT. In addition, another point on the curve which will be used for this evaluation is: 6000 GPM (3000 GPM per pump) @ 665 FT-TDH. Applying the pump affinity laws (Ref. 13) to these points yields new operating points on an "adjusted curve" as follows:

For the operating point of 6000 GPM @ 665 FT-TDH:

$$Q_{58.76Hz} = Q_{60Hz} * [58.76/60] = 6000 * [58.76/60] = 5876 \text{ GPM}$$

$$H_{58.76Hz} = H_{60Hz} * [58.76/60]^2 = 665 * [58.76/60]^2 = 638 \text{ FT}$$

And for the test point of 6350 GPM @ 644 FT-TDH:

$$Q_{58.76Hz} = Q_{60Hz} * [58.76/60] = 6350 * [58.76/60] = 6219 \text{ GPM}$$

$$H_{58.76Hz} = H_{60Hz} * [58.76/60]^2 = 644 * [58.76/60]^2 = 617 \text{ FT}$$

Since the potential reduction in pump speed would result in a reduction of both pump head, and pump flow, both of these factors must be accounted for in estimating the overall effect on flow. This overall reduction in flow will be estimated as the point where the "adjusted curve" (i.e., adjusted for a supply frequency of 58.76 Hz) crosses the original test head of 644 FT.

The "adjusted" points calculated above will be applied to the Point-Slope Form of the Straight-Line Equation to determine the slope of the "adjusted" head vs. system flow curve:

$$m = (Y_2 - Y_1) / (X_2 - X_1) = (638 - 617 / 5876 - 6219)$$
$$= -0.0612 \text{ FT/GPM}$$

The point where the adjusted curve passes through the head verified by the surveillance testing (i.e., 644 FT) is estimated by applying the straight line equation, and using the: 1) the slope of the adjusted curve (m); 2) the original test point, as adjusted for the reduction in speed (6219 GPM @ 617 FT); and, 3) the original test head of 644 FT:

$$Y_2 - Y_1 = m * (X_2 - X_1)$$

Where

m = -0.0612 FT/GPM

(X_1, Y_1) = (6219, 617) (The original test point of test point of 6350 GPM @ 644 FT as adjusted for a reduced pump speed)

$(X_2, Y_2) = (X_2, 644)$ (X_2 approximates the point where the "adjusted" curve passes through 644 FT)

Therefore:

$$644 - 617 = -0.0612 * (X_2 - 6219)$$

$$X_2 = (644 - 617) / -0.0612 + 6219 = 5778$$

The overall reduction in loop flow corresponding to the potential for a lower speed is therefore:

$$CS_{REDUCT\text{-}LOOP} = 6350 - 5778 = 572 \text{ GPM per loop}$$

And:

$$\sigma_{CSPump,Speed} = 572 / 2 = \underline{286 \text{ GPM}} \text{ per pump}$$

Note that the reduction in loop flow (572 GPM) would represent the uncertainty for a loop of Core Spray if both pumps were powered from the same diesel. However, since the pumps are powered from separate, independent diesels, the SRSS method can be applied to the uncertainty for a single pump (286 GPM) to determine the true uncertainty for a loop of Core Spray due to the potential for a lower diesel speed. Therefore:

$$\sigma_{CSLoop,Speed} = [(\sigma_{CSPump,Speed})^2 + (\sigma_{CSPump,Speed})^2]^{1/2}$$

$$= [(286)^2 + (286)^2]^{1/2}$$

$$\sigma_{CSLoop,Speed} = \underline{404 \text{ GPM}}$$

e) Combined Core Spray Uncertainties

Core Spray Single Loop Uncertainty (A or B Loop)

As previously identified, since the uncertainties due to pressure, flow and speed are independent, they can be combined via the SRSS method. Therefore:

$$UNCERT_{CS\text{-}1Loop} = [(\sigma_{CS,Flow})^2 + (\sigma_{CS,Press})^2 + (\sigma_{CSLoop,Speed})^2]^{1/2}$$

$$UNCERT_{CS\text{-}1Loop} = [(200)^2 + (384)^2 + (404)^2]^{1/2} = \underline{592 \text{ GPM}}$$

Since a loop of Core Spray is rated for, and tested to a flow of 6350 GPM, this uncertainty can be described in terms of a percentage:

$$UNCERT\%_{CS\text{-}1Loop} = 592 / 6350 \sim \underline{9.3 \%}$$

Core Spray Two Loop Uncertainty (A and B Loops)

For the two loop case, it is reiterated that each pump is powered from a separate diesel. In addition, since each loop is completely separate, with independent flow and pressure test instrumentation, the "A" loop and "B" the loop uncertainties are likewise independent, and can therefore be combined via the SRSS method:

$$UNCERT_{CS\text{-}2Loops} = [(UNCERT_{CS\text{-}1Loop})^2 + (UNCERT_{CS\text{-}1Loop})^2]^{1/2}$$

$$UNCERT_{CS\text{-}2Loops} = [(592)^2 + (592)^2]^{1/2} = \underline{837\ \ GPM}$$

The combined flow of both loops of Core Spray is 12,700 GPM (6350 x 2). Therefore, the two loop uncertainty, in terms of a percentage, is:

$$UNCERT\%_{CS\text{-}2Loops} = 837 / 12{,}700 \sim \underline{6.6\ \%}$$

II) RHR

a) Assumptions / Inputs

With respect to pump quarterly flow surveillance testing: [1b]

1) The Technical Specification surveillance requirement for an RHR pump is 12,200 GPM at a pump discharge pressure of 204/222 PSI for Unit 1/2.[2]

2) The overall accuracy of the flow and pressure readings obtained during quarterly pump surveillance testing is 2%.[3-5]

3) During RHR pump surveillance testing, the discharge pressure is read from PI-E11-1(2)R600A/B/C/D[1b], which has a full scale range of 0 - 600 PSI[6].

4) During surveillance testing, the pump flow is read from FR-E11-1(2)R608[1] or FI-E11-1(2)R603A/B, which have a full scale range of 0 - 30,000 GPM[6].

5) The pump test conditions are assumed to be 75°F, which corresponds to .4324 PSI per FT of pump head[7], or 2.313 FT per PSI.

6) The points on the pump curve which is verified via Unit 2 testing which will be used in this evaluation are obtained from Reference 12 and are: <u>12,000 GPM @ 502 FT-TDH</u>, and the test point of <u>12,200 GPM @ 492 FT-TDH</u>.

With respect to emergency diesel generator diesel testing: [9-10]

7) The assumed Technical Specification surveillance requirement for steady state diesel generator speed is 60 Hz +/- 2 %, or 58.8 Hz.[11]

8) The overall accuracy of the frequency measurement during diesel generator testing is 0.5%.[6]

b) Flow Uncertainty During Pump Testing

During testing, the actual loop flow could be less than the indication on FR-E11-1(2)R608 or FI-E11-1(2)R603A/B, which have a full scale range of 0 - 30,000 GPM. Per Input #2 the accuracy of these instruments is 2% of full scale. Therefore, the uncertainty induced due to flow instrumentation accuracy is:

$\sigma_{RHR,Flow}$ = .02 x 30,000 = 600 GPM

c) Discharge Pressure Uncertainty During Pump Testing

During testing, the actual loop flow could be less than the indication on PI-E11-1(2)R600A/B/C/D, which has a full scale range of 0 - 600 PSI. Per Input #2 the accuracy of the instrument is 2% of full scale. Therefore, the actual pressure could be 12 PSI (.02 x 600) less than indicated. Per Input #5 above, this corresponds to approximately: 12 ~~PSI~~ * 2.313 FT/~~PSI~~ = 28 FT of pump head.

From Reference 12 and per Input #6 above, the slope of the RHR pump curve at the test flow of 12,200 GPM (12,000 - 12,200) / (502 - 492) = -20 GPM/FT. Therefore, the equivalent reduction in flow corresponding to a 23 FT reduction in head is:

$\sigma_{RHR,Press}$ = 20 GPM/~~FT~~ x 28 ~~FT~~ = 560 GPM

d) Uncertainty Due To The Potential For Lower Diesel Speed

Per Section 1d above, the minimum expected diesel speed is 58.76 Hz.

Per Reference 12 and Input #6 above, the point on the RHR pump curve which is verified via the Unit 2 surveillance testing is: 12,200 GPM @ a pump total developed head of about 492 FT. In addition, another point on the curve which will be used for this evaluation is: 12,000 GPM @ 502 FT-TDH. Applying the pump affinity laws (Ref. 13) to these points yields new operating points on an "adjusted curve" as follows:

For the operating point of 12,000 GPM @ 502 FT-TDH:

$Q_{58.76Hz}$ = Q_{60Hz} * [58.76 / 60] = 12,000 * [58.76 / 60] = 11,752 GPM

$H_{58.76Hz}$ = H_{60Hz} * $[58.76 / 60]^2$ = 502 * $[58.76 / 60]^2$ = 481 FT

And for the test point of 12,200 GPM @ 492 FT-TDH:

$$Q_{58.76Hz} = Q_{60Hz} * [58.76/60] = 12{,}200 * [58.76/60] = 11{,}948 \text{ GPM}$$

$$H_{58.76Hz} = H_{60Hz} * [58.76/60]^2 = 492 * [58.76/60]^2 = 472 \text{ FT}$$

Since the potential reduction in pump speed would result in a reduction of both pump head, and pump flow, both of these factors must be accounted for in estimating the overall effect on flow. This overall reduction in flow will be estimated as the point where the "adjusted curve" (i.e., adjusted for a supply frequency of 58.76 Hz) crosses the original test head of 492 FT.

The "adjusted" points calculated above will be applied to the Point-Slope Form of the Straight-Line Equation to determine the slope of the "adjusted" head vs. system flow curve:

$$m = (Y_2 - Y_1) / (X_2 - X_1) = (481 - 472 / 11{,}752 - 11{,}948)$$

$$= -0.0459 \text{ FT/GPM}$$

The point where the adjusted curve passes through the head verified by the surveillance testing (i.e., 492 FT) is estimated by applying the straight line equation, and using the: 1) the slope of the adjusted curve (m); 2) the original test point, as adjusted for the reduction in speed (11,948 GPM @ 472 FT); and, 3) the original test head of 492 FT:

$$Y_2 - Y_1 = m * (X_2 - X_1)$$

Where

m = -0.0459 FT/GPM

(X_1, Y_1) = (11948, 472) (The original test point of test point of 12,200 GPM @ 492 FT as adjusted for a reduced pump speed)

(X_2, Y_2) = $(X_2, 492)$ (X_2 approximates the point where the "adjusted" curve passes through 492 FT)

Therefore:

$$492 - 472 = -0.0459 * (X_2 - 11948)$$

$$X_2 = (492 - 472) / -0.0459 + 11948 = 11512$$

The overall reduction in a single pump flow corresponding to the lower pump speed is therefore:

$$\sigma_{RHR,Speed} = 12{,}200 - 11{,}512 = \underline{688 \text{ GPM}}$$

e) Combined LPCI Uncertainties

LPCI One Pump Uncertainty (1 Pump in 1 Loop)

As previously identified, since the single pump uncertainties due to pressure, flow and speed are independent, they can be combined via the SRSS method. Therefore, the single pump uncertainty is:

$$UNCERT_{RHR\text{-}1Pump} = [(\sigma_{RHR,Flow})^2 + (\sigma_{RHR,Press})^2 + (\sigma_{RHR,Speed})^2]^{1/2}$$

$$UNCERT_{RHR\text{-}1Pump} = [(600)^2 + (560)^2 + (688)^2]^{1/2} = \underline{1071} \text{ GPM}$$

Since a single RHR pump is rated for, and tested to a LPCI flow of 12,200 GPM, this uncertainty can be described in terms of a percentage:

$$UNCERT\%_{RHR\text{-}1Pump} = 1071 / 12{,}200 = 0.0878 \sim \underline{8.8\ \%}$$

LPCI Two Pump Uncertainty (1 Pump in Each of 2 Loops)

For the two pump case, one pump from each loop is available. Each pump is powered from an independent diesel, and is completely separated, with independent flow and pressure test instrumentation. The pump uncertainty for the two pump case (1 pump in each loop) can therefore be calculated by applying the SRSS method to the one pump uncertainty:

$$UNCERT_{RHR\text{-}2Pumps} = [(UNCERT_{RHR\text{-}1Pump})^2 + (UNCERT_{RHR\text{-}1Pump})^2]^{1/2}$$

$$UNCERT_{RHR\text{-}2Pumps} = [(1071)^2 + (1071)^2]^{1/2} = \underline{1515} \text{ GPM}$$

The combined flow of two pumps, with one in each loop, is 24,400 GPM (12,200 x 2). Therefore, the two pump uncertainty, in terms of a percentage, is:

$$UNCERT\%_{RHR\text{-}2Pumps} = 1515 / 24{,}400 \sim \underline{6.2\ \%}$$

LPCI One Loop Uncertainty (2 Pumps in the Same Loop)

For the one loop case, it is postulated that a single complete loop (i.e., with two pumps) is available. In this case, both pumps are powered from separate diesels, and tested with separate pressure instrumentation. However, since the same flow instrument is used to test the performance of each pump, this is not an independent variable. Therefore, the uncertainty due to flow instrumentation must be accounted for separately.

Since both diesel speed and the pressure terms are independent for each pump, these terms may be combined for each pump as follows:

$$UNCERT_{Pump} = [(\sigma_{RHR,Press})^2 + (\sigma_{RHR,Speed})^2]^{1/2} = [(560)^2 + (688)^2]^{1/2}$$
$$= 887 \text{ GPM}$$

This term is included for each pump, along with the flow uncertainty to determine the total uncertainty for the one loop case as follows:

$$UNCERT_{RHR\text{-}1Loop} = [(2 \times (887)^2) + (2 \times \sigma_{RHR,Flow})^2]^{1/2}$$

$$UNCERT_{RHR\text{-}1Loop} = [(887)^2 + (887)^2 + (2 \times 600)^2]^{1/2} = \underline{1736 \text{ GPM}}$$

Since a single loop of LPCI is rated for a flow of 21,300 GPM, this uncertainty can be described in terms of a percentage:

$$UNCERT\%_{RHR\text{-}1Loop} = 1736 / 21{,}300 \quad \sim \underline{8.2 \%}$$

<u>**LPCI Two Loop Uncertainty (4 Pumps: 2 Pumps Available in Both Loops)**</u>

For the two loop case, each pump is powered from a separate diesel, and each loop is completely separated, with independent flow and pressure test instrumentation. Hence, the "A" loop and "B" loop uncertainties are likewise independent, and can therefore be combined via the SRSS method:

$$UNCERT_{RHR\text{-}2Loops} = [(UNCERT_{RHR\text{-}1Loop})^2 + (UNCERT_{RHR\text{-}1Loop})^2]^{1/2}$$
$$= [(1736)^2 + (1736)^2]^{1/2} = \underline{2455 \text{ GPM}}$$

The combined flow of both loops of LPCI is 42,600 GPM (21,300 x 2). Therefore, the two pump uncertainty, in terms of a percentage, is:

$$UNCERT\%_{RHR\text{-}2Loops} = 2455 / 42{,}600 \quad \sim \underline{5.8 \%}$$

III) DESIGN BASIS LOCA CASES

a) <u>Discussion</u>

From Sections I.e. and II.e above, it is seen that the uncertainties for individual Core Spray and RHR subsystems range from 5.8% to 9.3%. It is also seen that when more pumps are considered in combination, the overall uncertainty decreases. The reason for this is that when more than one pump is considered, the mean flows are added and the flow variances are added. However, the total uncertainty in terms of percentage (UNCERT%), equals the total standard deviation (UNCERT) divided by the total flow. Since the standard deviation is the square root of the variance, the root of the variance is divided by the increase flow. This process results in a lower uncertainty when expressed in terms of percentage.

To illustrate, if four identical pumps are considered, the total flow rate is 4 times the flow rate of one pump and the total variance is 4 times the variance of one pump. However, the total uncertainty percentage (UNCERT%) is total standard deviation (i.e., the square root of variance) the divided by the total flow. Since the standard deviation is the square root of the variance, this amounts to only 1/2 of the percent uncertainty of each pump.

Conversely, with fewer pumps, the total percent uncertainty will be higher. It follows that higher uncertainties will exist for design basis accident scenarios with fewer pumps available. Table 6.3-5 of the FSAR identifies the most limiting Design Basis LOCA break locations along with the most limiting single failures. That table also identifies the ECC sub-systems which remain available for these most limiting scenarios. The six cases identified below identify the uncertainties for all of the scenarios identified in that table.

Finally, note that for these cases, the diesel combination which posses the largest affect on uncertainty will be utilized. In practice, if each pump is assumed to be powered by a separate, independent diesel, a lower uncertainty will result. However, for this assessment, a diesel/pump lineup which results in the largest uncertainty will be assumed.

b) CASE 1 - <u>One Loop Core Spray Loop AND One LPCI Pump</u>

Number of Pumps Available: **3**
Total Design Rated Flow: **18,550 GPM** = (1 x 6350) + (1 x 12,200)
Applicable Break / Single Failure Scenarios:

- Recirc Discharge / False LOCA
- Recirc Discharge / Battery (*)
- Recirc Discharge / Diesel Generator (*)

To conservatively estimate the effects of diesel speed, it will be assumed that the diesel which is supplying one of the Core Spray pumps is also supplying the available RHR pump. Therefore:

$$UNCERT_{CASE1} = [(\sigma_{CS,Flow})^2 + (\sigma_{CS,Press})^2 + (\sigma_{RHR,Flow})^2 + (\sigma_{RHR,Press})^2 + (\sigma_{CSPump,Speed})^2 + (\sigma_{CSPump,Speed} + \sigma_{RHR,Speed})^2]^{1/2}$$

$$= [(200)^2 + (384)^2 + (600)^2 + (560)^2 + (286)^2 + (286 + 688)^2]^{1/2}$$

$$UNCERT_{CASE1} = \mathbf{1375\ GPM}$$

$$UNCERT\%_{CASE1} = \mathbf{1375 / 18{,}550 \sim \underline{7.4\ \%}}$$

(*) Note that for the battery and diesel generator failure scenarios, no credit is taken for a third Core Spray pump which could be available per FSAR Table 6.3-5. The rated flow of the "uncredited" third Core Spray pump (3175 GPM) exceeds the calculated uncertainty of 1375 GPM.

c) CASE 2 - One Loop Core Spray Loop AND Two LPCI Pumps (One Per Loop)

Number of Pumps Available: **4**
Total Design Rated Flow: **30,750 GPM** = (1 x 6350) + (2 x 12,200)
Applicable Break / Single Failure Scenarios:

- Recirc Suction / False LOCA

This case is similar to Case 1 in that a diesel which is supplying one of the Core Spray pumps is also supplying one of the available RHR pumps. However, in addition, since two RHR pumps in separate and independent divisions are available, it follows that a third diesel must be supplying the second RHR pump. The uncertainty from Case 1 can therefore be combined via the SRSS method with the uncertainty of a single RHR pump ($UNCERT_{RHR-1Pump}$ = 1071 GPM), as calculated in Section II.e above..

$$UNCERT_{CASE2} = [(UNCERT_{CASE1})^2 + (UNCERT_{RHR-1Pump})^2]^{1/2}$$

$$= [(1375)^2 + (1071)^2]^{1/2}$$

$$UNCERT_{CASE2} = 1743 \text{ GPM}$$

$$UNCERT\%_{CASE2} = 1743 / 30,750 \sim \underline{5.7 \ \%}$$

d) CASE 3 - One Loop Core Spray Loop AND Three LPCI Pumps (One Complete LPCI Loop plus One Pump in Other Loop)

Number of Pumps Available: **5**
Total Design Rated Flow: **39,850 GPM** = (1 x 6350) + (1 x 21,300) + (1 x 12,200)
Applicable Break / Single Failure Scenarios:

- Recirc Suction / Battery (*)
- Recirc Suction / Diesel Generator (*)

For this case, three diesels are available. The most conservative line-up assumes that the division which powers Core Spray also supplies a complete loop of RHR. In addition, the remaining RHR pump is powered from a diesel in the opposite division. For this configuration, the uncertainty for the single RHR pump is equal to one pump uncertainty ($UNCERT_{RHR-1Pump}$ = 1071 GPM), as calculated in Section II.e above.

The uncertainty due to the complete division of two Core Spray and two LPCI pumps must account for the fact that they are powered from the same pair of diesels. Also, the fact that the RHR pump flow instrumentation uncertainties are not independent must be accounted for as previously outlined in the LPCI one loop

uncertainty case in Section II.e above. The uncertainty due to a complete division of Core Spray and LPCI is:

$$UNCERT_{CS\&RHR} = [(\sigma_{CS,Flow})^2 + (\sigma_{CS,Press})^2 + (2 \times \sigma_{RHR,Flow})^2 + (2x(\sigma_{RHR,Press})^2) + (2x(\sigma_{CSPump,Speed} + \sigma_{RHR,Speed})^2]^{1/2}$$

$$= [(200)^2 + (384)^2 + (2 \times 600)^2 + (2 \times 560)^2 + (2 \times (286 + 688)^2)]^{1/2}$$

$$= 2038 \text{ GPM}$$

(Note: 2038 / (6350+21300) ~ 7.4% for a complete ECCS Division)

Applying the SRSS method to this uncertainty and the LPCI one pump uncertainty yields:

$$UNCERT_{CASE3} = [(UNCERT_{CS\&RHR})^2 + (UNCERT_{RHR\text{-}1Pump})^2]^{1/2}$$

$$= [(2038)^2 + (1071)^2]^{1/2}$$

$$UNCERT_{CASE3} = 2302 \text{ GPM}$$

$$UNCERT\%_{CASE3} = 2302 / 39{,}850 \sim \underline{5.8\ \%}$$

(*) Note that for these scenarios, no credit is taken for a third Core Spray pump which could be available per FSAR Table 6.3-5. The rated flow of the "uncredited" third Core Spray pump (3175 GPM) exceeds the calculated uncertainty of 2302 GPM.

e) CASE 4 - Two Core Spray Loops

Number of Pumps Available: **4**
Total Design Rated Flow: **12,700** GPM = (2 x 6350)
Applicable Break / Single Failure Scenarios:

- Recirc Discharge / LPCI Injection Valve

The uncertainty for this case is determined in the Core Spray two loop uncertainty case in Section I.e above.

$$UNCERT_{CASE4} = UNCERT_{CS\text{-}2Loops} = \underline{837\ GPM}$$

$$UNCERT\%_{CASE4} = UNCERT\%_{CS\text{-}2Loops} = 837 / 12{,}700 \sim \underline{6.6\ \%}$$

f) CASE 5 - Two Core Spray Loops AND One LPCI Loop

Number of Pumps Available: 6
Total Design Rated Flow: 34,000 GPM = (2 x 6350) + (1 x 21,300)
Applicable Break / Single Failure Scenarios:

- Recirc Suction / LPCI Injection Valve
- Recirc Discharge / HPCI

Since all four Core Spray pumps are available, all diesels must be in operation. In this configuration, a complete divisional complement of RHR and Core Spray pumps are available, and the opposite loop of Core Spray is likewise available.

The uncertainty due to a complete division of two Core Spray and two LPCI pumps was calculated above in Case 3 and was determined to be:

$$UNCERT_{CS\&RHR} = 2038 \text{ GPM}$$

The uncertainty for the opposite loop of Core Spray is identified as the Core Spray single loop uncertainty as determined in Section I.e above:

$$UNCERT_{CS\text{-}1Loop} = 592 \text{ GPM}$$

Applying the SRSS method to these uncertainties yields:

$$UNCERT_{CASE5} = [(UNCERT_{CS\&RHR})^2 + (UNCERT_{CS\text{-}2Loops})^2]^{1/2}$$

$$= [(2038)^2 + (592)^2]^{1/2}$$

$$UNCERT_{CASE5} = 2123 \text{ GPM}$$

$$UNCERT\%_{CASE5} = 2123 / 34{,}000 \sim \underline{6.2\ \%}$$

g) CASE 6 - Two Core Spray Loops AND Two LPCI Loops

Number of Pumps Available: 8
Total Design Rated Flow: **55,300** GPM = (2 x 6350) + (2 x 21,300)
Applicable Break / Single Failure Scenarios:

- Recirc Suction / HPCI

In this case, all low pressure ECC subsystems in both divisions are available. The uncertainty due to a complete division of two Core Spray and two LPCI pumps was calculated above in Case 3 and was determined to be:

$UNCERT_{CS\&RHR}$ = 2038 GPM

Applying the SRSS method to account for both separate, independent divisions yields:

$$UNCERT_{CASE6} = [(UNCERT_{CS\&RHR})^2 + (UNCERT_{CS\&RHR})^2]^{1/2}$$

$$= [(2038)^2 + (2038)^2]^{1/2}$$

$UNCERT_{CASE6}$ = **2882** GPM

$UNCERT\%_{CASE6}$ = **2882 / 55,300 ~ 5.2 %**

IV) CONCLUSIONS

The following table summarizes the rated flows for the available RHR and Core Spray systems, along with the associated uncertainties for the most limiting SSES Design Basis Accident scenarios:

↓Single Failure / Break→	Recirc Suction	Recirc Discharge
False LOCA	30,750 GPM / 5.7 %	18,550 GPM / 7.4 %
Battery	39,850 GPM / 5.8 % (*)	18,550 GPM / 7.4 % (*)
LPCI Injection Valve	34,000 GPM / 6.2 %	12,700 GPM / 6.6 %
Diesel Generator	39,850 GPM / 5.8 % (*)	18,550 GPM / 7.4 % (*)
HPCI	55,300 GPM / 5.2 %	34,000 GPM / 6.2 %

(*) Note that for the battery and diesel generator failure scenarios, no credit is taken for a third Core Spray pump which could be available per FSAR Table 6.3-5. For these cases, the rated flow of the "uncredited" third Core Spray pump (3175 GPM) exceeds the calculated uncertainties.

V) REFERENCES

1a) SO-151-A02, Rev. 2, SO-151-B02, Rev. 2, SO-251-A02, Rev. 2, SO-251-B02, Rev. 2, "Quarterly Core Spray Flow Verification - Division I (II)"

1b) SO-149-A02, Rev. 1, SO-149-B02, Rev. 1, SO-249-A02, Rev. 1 SO-249-B02, Rev. 1, "Quarterly RHR Flow Verification - Division I (II)"

2) SSES Current Technical Specification (CTS) 4.5.1.b.1 & 4.5.1.b.2 - Emergency Core Cooling Systems Surveillance Requirements (Core Spray & RHR)

3) NDAP-QA-0423, Rev. 6, "Station Pump and Valve Testing Program"

4) ISI-T-100.0, Rev. 15 & ISI-T-200.0, Rev. 12, "InService Inspection Program Plan For Pump and Valve Operational Testing"

5) ASME OMa-1988, Parts 6 & 10

6) SSES Nuclear Information Management System Database (NIMS)

7) Crane Technical Paper No. 410, "Flow of Fluids", 21st Printing, 1982

8) EC-051-1006, Rev. 0, "Core Spray System: Determination of Pump Flow at Reduced Emergency Diesel Generator Speeds and Determination of Pump Discharge Test Pressure"

9) SE-124-107, Rev. 8 & SE-224-107, Rev. 5, "18 Month Diesel Generator 'A' and 'C' (or 'E') Auto Start and ESS Buses 1(2)A and 1(2)C Energization on Loss Of Offsite Power with a LOCA - Plant Shutdown"

10) SE-124-207, Rev. 9 & SE-224-207, Rev. 5, "18 Month Diesel Generator 'B' and 'D' (or 'E') Auto Start and ESS Buses 1(2)B and 1(2)D Energization on Loss Of Offsite Power with a LOCA - Plant Shutdown"

11) SSES Improved Technical Specification (ITS) SR 3.8.1.7, 3.8.1.9, & 3.8.1.11 - Electrical Power Systems Surveillance Requirements

12) EC-049-1025, Rev. 0 (Draft), "RHR System: Determination of LPCI Pump Flow at Reduced Emergency Diesel Generator Speeds and Determination of Pump Discharge Test Pressure"

13) Cameron Hydraulic Data, Ingersoll-Rand Inc., 17th Edition, 1st Printing

14) FF126510, Sheet 3101, Rev. 1, "Report of Performance Test for Pump S/N 107383" (Core Spray - 2P206C)

15) FF124510, Sheet 5301, Rev. 0, "Report of Performance Test for Pump S/N 0573314" (RHR - 2P202C)

16) "Radiation Detection and Measurement", Knoll, Glenn F., John Wiley & Sons, Inc., 1979

Attachment 2

Effects of 2% Frequency Variation on Plant Systems and Components

I) DISCUSSION

With the implementation of Improved Technical Specifications (ITS), the allowable steady state operating frequency band for the emergency diesel generators is 58.8 Hz (60 +/- 1.2 Hz)[1]. The purpose of this licensing requirement (i.e., a 2% allowance band on diesel generator speed) is to assure that on-site emergency power is of an adequate quality, such that proper operation of electrical devices, such as relays, transformers, solenoids, etc., is assured. However, it is PP&L's position that this 2% speed tolerance need **not** be considered as a penalty in evaluating the performance of mechanical equipment/systems such as pumps, fans, compressors, etc.

As the result of conservative "over-design" margins which are inherent in nuclear power plant components and systems, a 2% increase in speed would not impose excessive stresses, nor cause unusual "wear and tear" on equipment during accident periods. Further, the relatively modest shortcomings in equipment performance which would result from a 2% decrease in power supply frequency are offset by the inherent conservatism of SSES licensing and design basis evaluations. In addition, The uncertainties in equipment performance, which are induced by the potential for a 2% reduction in the power supply frequency, are accounted for by conservative assumptions and methodologies which are mandated by regulatory analytical practices.

II) PURPOSE

The purpose of this evaluation is to provide a qualitative assessment addressing the impact on (the performance of) large mechanical components/systems. which results from a potential 2% reduction in diesel speed (and hence a lower power supply frequency). It will be demonstrated that this potential either: 1) does not in any way impact system operation; or, 2) does not adversely affect the system/component capability to satisfactorily perform its design intended function. Hence, the potential for a 2% lower diesel power supply frequency imposes no implications to plant safety.

III) EVALUATION

In the vast majority of cases, the actual uncertainty of equipment performance which is induced by the subject allowance band in diesel generator frequency is actually less than 2%. This is due to the fact that for any given diesel, there is an equal probability that diesel speed (and hence the speed of rotating equipment) could be conservatively high. Since most safety-related systems contain redundant, 100% capacity components which serve the same function, the overall uncertainty induced by the potential for lower speed decreases so long as each component is supplied by a separate diesel.

For example, if two identical pumps are considered, the total flow rate is 2 times the mean flow rate and the total variance is 2 times the variance of one pump. However, the total uncertainty, in terms of percentage, is the total standard deviation (i.e., the square root of variance) divided by the total flow. Since the standard deviation is the square root of the variance, the uncertainty associated with the 2% allowance band is [2% x (SQRT(2))/2] = [2% x (1.41/2)] = [2% x (0.71)] = 1.42 %.

Therefore, the actual expected reduction in flow would be less than 2%. Similarly, the associated uncertainty is [2% x (SQRT(3))/3] =1.16 % if three pumps are considered and the associated uncertainty is [2% x (SQRT(4))/4] = 1.0% if four pumps are considered.

The uncertainty in performance for most safety related, redundant systems will therefore be less than 2%. Nonetheless, the evaluation below will assess the effects of a full 2% reduction in diesel speed on large mechanical components and systems.

A) Reactivity Control

1) Control Rod Drives

The CRD system pumps are not required for the emergency SCRAM function. The motive force for the rapid insertion of the control rod drives is provided via stored hydraulic/pneumatic energy (i.e., CRD accumulators) and the reactor vessel pressure itself. Hence, the ability for the CRD system to execute a SCRAM is unaffected by a 2% reduction in diesel speed.

2) SBLC Pumps

During an ATWS, two SBLC pumps would be initiated to inject sodium-pentaborate into the vessel. Since two independent pumps would be in operation and powered by separate diesels, , the uncertainty in equipment performance associated with the 2% allowance band is actually 1.42 %.

The SBLC pumps are positive displacement pumps and their discharge head characteristics would not be affected by a reduction in pump speed, but a proportional reduction in flow would occur. However, the potential for a slight reduction in diesel supply frequency is not seen to impact the conclusions of the SSES ATWS analysis[3] for several reasons. First, the SSES administrative concentration of sodium pentaborate is maintained higher than that required by Technical Specifications. While the Tech Spec allowable concentration ranges from 13.4% to 12.6% (by weight),[9d] the minimum administrative concentration is 13.6%.[25,26] Hence, the actual concentration of the solution injected is at least 1.5% higher than that required in Tech Specs. Although the SBLC pumps may run slightly slower when powered by the diesels, this higher concentration would act to offset the effects of a lower pump speed and thus assure that the required quantity of sodium pentaborate is injected to the vessel in a timely manner. Secondly, the ATWS case which involves a Loss of Off-site Power, which is when the diesels would be supplying the SBLC pumps, is not the most liming event with respect to peak vessel pressure, suppression pool temperature, nor fuel cladding temperature.

Finally, as a result of the low event probabilities, the regulatory assumptions which govern plant specific ATWS evaluations allow for the use of nominal values. Since there is an equal probability that the diesel supply frequency could be 2% above the 60 Hz setpoint, it is acceptable to assume a nominal supply frequency of 60 Hz. Since the

ATWS rules allow for the use of nominal values, it is not a licensing requirement to assume a penalty for a potential 2% reduction in emergency diesel generator speed.

B) RPV Pressure Boundary

1) Main Steam Safety Relief Valves

The primary means for overpressure protection of the reactor vessel are the Main Steam Safety Relief Valves (MSRVs). These valves have several modes of operation, none of which are affected by a reduction in diesel speed. In the "safety mode", which is the only mode governed by Technical Specifications, the valves are directly actuated by vessel pressure. In the non-safety-related "relief mode", the valves are opened, and maintained in the open position, via stored pneumatic energy (i.e., accumulators). None of the components which are required for valve operation rely on AC power sources and hence valve operation is not impacted by lower diesel speeds.

C) ECCS

1) HPCI / RCIC Systems/Pumps

The HPCI and RCIC system major support components are powered by DC electrical sources and do not require AC power for operation. The motive power for the pumps is supplied by steam driven turbines. As such, they are not impacted by a 2% reduction in diesel speed.

2) ADS

As with the other modes of MSRV operation, the motive force to actuate the ADS function of the valves is provided via stored pneumatic energy (i.e., accumulators and stored N_2 bottles). The function of the ADS system is therefore unaffected by a 2% reduction in diesel speed.

3) RHR & Core Spray Pumps

The need to account for the impacts of uncertainties in ECCS flow-rates, which are induced by a 2% reduction in diesel speed, in the SSES LOCA analyses is addressed in an engineering position paper which has been prepared by the Nuclear Fuels Group.(24) It has been concluded that NRC regulations do not explicitly require an analytical allowance for diesel generator frequency uncertainties in Appendix "K" methods. In addition, these methodologies, which are used for the SSES LOCA analyses, are conservative and consistent with the NRC's current expectations. Hence, the inclusion of such allowances is not needed to assure the health and safety of the public.

D) Containment Heat Removal

The design of the SSES units provides for two independent loops of decay/accident heat removal, and only one is needed for design basis accident mitigation. Each independent loop consists of an RHR heat exchanger which can be supplied by either of two 100% capacity RHR pumps. In addition, as a result of the "cross-unit" RHR Service Water (RHR SW) arrangement, each heat exchanger can be cooled by either of two 100% capacity RHR SW pumps. The redundancy of this configuration provides for a high level of system reliability and assures the adequate capability for decay/accident heat removal. Since multiple pumps are supplied by different diesels, the uncertainty in equipment performance associated with the 2% allowance band is at most 1.42 %. This notwithstanding, the following discussion is provided to demonstrate that any RHR / RHR SW pump combination would provide adequate post accident flows, even if both pumps operated under a 2% speed reduction.

1) RHR

A 2% reduction in speed will not impact the RHR pumps' ability to provide the design rated shell side heat exchanger flow of 10,000 GPM for post accident decay heat removal. Although a lower pump speed affects both flow and total developed head (TDH), the suppression pool return valves are throttled to only about 10-15% open when RHR is in the suppression pool cooling mode.[4] This is due to the fact that the suppression pool cooling line losses are relatively small when compared to the total developed head of the pump. The difference is taken up by throttling the return valve, which results in a large valve delta-P. If pump performance (i.e., flow and TDH) were to decrease because of a lower speed, a system flow of 10,000 GPM could still be easily established by further opening the return valve. Therefore, a 2% reduction in pump speed will not affect post accident RHR cooling flow.

2) RHR SW

In Figure 1, the pump curve for a typical SSES RHR SW pump is plotted.[5] The pump affinity laws were used to calculate a "degraded" curve corresponding to a pump speed of 58.8 Hz which is also plotted. Finally, a system resistance curve, which corresponds to a flow of 9000 GPM at 100% pump speed, is identified. Note that this system resistance curve would be established by operators via the throttling of the RHRSW heat exchanger inlet valve in accordance with operating procedures.[6] If pump performance were to decrease because of a lower speed, the RHR SW flow through the heat exchanger would decrease to the point where the system resistance curve intersects the degraded curve. By inspection, it is seen that this flow is approximately 8750 GPM. This flow is well in excess of the minimum required RHR SW flow of 8000 GPM, as identified in Reference 7. Therefore, a 2% reduction in pump speed will not adversely affect post accident RHR SW cooling flow.

E) ESW / DIESEL COOLING

1) ESW System

ESW system supplies cooling water to the emergency diesel generators, the ECCS pump room coolers (RHR, CS, HPCI/RCIC), the RHR pump motor oil coolers, the control structure chillers, and the Unit 2 direct expansion units. These loads are also addressed in other sections, but the following discussion is provided to demonstrate that the potential for a 2% reduction in diesel speed will not threaten adequate cooling for emergency loads.

Performance Uncertainty

During a Design Basis Accident, at least one loop of ESW (i.e., two pumps) would be in operation. Since all ESW pumps are supplied by separate diesels, the associated uncertainty in equipment performance for a two pump configuration is actually 1.42 %. Likewise, the uncertainties associated with three and four pump operating configurations is 1.16% and 1.0% respectively.

Spray Pond / ESW Short Term Temperatures

The design basis flows for all ESW users is based on the maximum spray pond design temperature of 97°F.[8] The maximum administrative operating limit of 85°F[9a] assures that the 97°F threshold will not be exceeded, even with the worst case single failure for spray pond temperature; a failure of an ESW return bypass valve to close. (This failure can prevent the effective use of the spray arrays and hence results in higher spray pond temperatures.)

The spray pond temperature profile following a Design Basis Accident increases by about two degrees-F in the first three hours of an accident; from 85.5°F to 87.6°F.[10] Subsequently, after six hours, temperature increases to 90.6°F and then to 93.4°F at twelve hours. With the inability to close a loop's bypass valve, appropriate operator actions are taken but spray pond temperature continues to increase to 95.9°F at 24 hours and peaks at 97.42°F at t=44 hours. Soon thereafter, a downward trend in temperature occurs. Based on this profile, ESW users would be supplied with relatively low temperature cooling water during the initial stages of an accident. As a result of lower initial supply temperatures, as well as the fact that margin exists between the actual and minimum required ESW cooler flows,[11] it is reasonable to expect that all ESW users would be adequately cooled, even if diesel speeds (and hence pump speeds) were to be slightly lower.

ESW System Performance

Two ESW pumps are capable of supplying all required emergency loads during a DBA (i.e., four diesels and a complete division of safety-related equipment).[11] In addition, for most DBA scenarios, it is expected that a minimum of three pumps would be

available; the only single failures which would prevent the auto-initiation of at least three pumps is the loss of 125 VDC batteries 1D614 or 1D624. However, for these specific single failures, it is expected that two pumps would nonetheless provide for adequate cooling in the short term, even with a 2% reduction in speed. This is due to the fact that spray pond temperatures will be less than the design basis temperature limit of 97°F as described above. In the short term, the cooler supply temperatures would act to offset the effects of a slightly lower flow which might occur if only two pumps were available and operating at a lower speed.

In the event of a failure of 1D614 or 1D624, additional pumps could be placed in service by transferring their control power from the failed battery to the corresponding Unit 2 battery (2D614 or 2D624). At this point, at least three pumps would be available and capable of supplying all required loads as described below:

In Figure 2, the pump curve for a typical SSES ESW pump is plotted.[12] Also plotted is the equivalent curve for two pump operation in parallel, as well as a conservative system resistance curve which intersects the two pump curve at a flow of 7000 GPM. This flow was selected because it bounds the flow requirements of a single loop of ESW.[8] Finally, a "degraded" curve is plotted which corresponds to three pumps operating with a 2% reduction in speed (58.8 Hz). By inspection, it is seen that 7000 GPM, the "degraded" three-pump curve is above the "normal" two pump curve, which is known to provide adequate flow to the associated users.[11] Therefore, as long as three ESW pumps are available, they would be able to provide adequate flow and head even when operated with a 2% reduction in speed.

Spray Cooling

As a final note, it should be identified that the potential for a 2% reduction in ESW pump speed will not result in inadequate spray cooling. This is due to the fact that guidelines have been developed and incorporated into the appropriate operating procedures[6] which provide direction for the optimum use of the spray networks, based on system flow. Therefore, operators have the required information and operating guidelines to effectively use the spray networks and optimize spray cooling regardless of actual system/loop flow.

2) Emergency Diesel Generator Cooling

Based on the discussion above, it is reasonable to expect that the emergency diesel generators would be provided enough cooling to provide for the disbursement of their design heat load. Hence, a 2% reduction in ESW pump speed would not affect either the short or long term phases of diesel operation during accident scenarios.

In the short term phase, just after diesel start, the engine is cold and operation can continue for several minutes without cooling.[13] In addition, during this point of the accident, cooler inlet temperatures would be at least 12°F cooler than assumed in the diesel heat exchanger design calculations. (The heat exchanger design calculations

assume an inlet temperature equal to the ESW spray pond design limit of 97°F, whereas the pond temperature at the start of the event would be at most 85°F - the Tech Spec administrative limit.)

In the longer term, it is expected that at least three ESW pumps would be available as described above, and hence the diesels would be supplied with their design flow rates. In addition, it should be noted that if a diesel were running with a 2% slower steady state speed, the mechanical components it powers would also be running 2% slower. Under these conditions, the work done by these mechanical components would be less, and hence their associated load on the diesel would be less. With a lower diesel load, the cooling requirements would likewise be less. Hence, it is concluded that unacceptable diesel operating conditions would not result from any potential shortcomings in ESW flow due to a 2% reduction in diesel speed.

F) <u>HVAC</u>

1) <u>Control Structure Chilled Water</u>

The Control Structure Chilled Water (CSCW) system consists of two independent chiller trains, each of which has a 100% capacity of 202 tons with the maximum ESW supply temperature of 97°F, and a loop supply temperature of 44°F.(14) In general, the entire temperature profile in the control structure during Design Basis Accidents qualifies as a "mild" environment. This is evidenced by the fact that equipment qualification is not required for components in the building. Unlike the reactor building, which is completely isolated under accident conditions, outside air is drawn into the control structure through the CREOASS trains. The overall heat load is therefore dependent not only on the building's internal heat load, but also on the on outside air temperature which varies throughout the day.

There are several ways in which a 2% lower diesel speed would affect the CSCW system. There are a number of components which would operate at a lower speed, and hence provide lower flows. These components include the system's outside supply and area cooling fans, the condenser circ and loop circ pumps, as well as the chiller's centrifugal compressor. In general, with a lower compressor speed, the available capacity of the chiller will decrease since the overall flow rate of the refrigerant will decrease.

With the fans and loop circ pumps providing lower flows, the actual heat load induced on the chiller will be lower, since lower flows would remove less heat from the cooled areas. The net effects of a 2% reduction in diesel speed would result in a steady state equilibrium operating point for the system with slightly higher room/area temperatures. This steady state operating point will not only be a function of these areas temperatures, but also of the chilled loop supply/return temperatures, outside air (i.e., supply) temperatures, and the ESW supply temperature and flow.

A review of the building temperature response during accidents was performed.[15] That analysis considers the effect of variable chiller loads and loop supply temperatures, as well as outside air temperature. When loop supply temperature is increased by 6°F (from 44°F to 50°F), chiller load is reduced by up to 20 tons (about 10%), and peak room/area temperatures increase by an average of about 4°F - 5°F. In addition, all peak temperatures do not occur until 720 hours (30 days) after the start of the accident. With a 2% reduction in diesel speed, it is expected that peak room/area temperatures would be slightly higher than those calculated for 100% equipment speed. However, temperatures for those areas which are cooled by the CSCW system would nonetheless still fall within the envelope which defines a "mild" environment.

In addition, as the result of the thermal inertia of the entire building and system, the effect of a slower diesel speed would be slow to develop. This slow response, coupled with the 30 day time required to reach peak room/area temperatures, would provide for an adequate "buffer" to allow for operators to diagnose unusual control structure environmental conditions. Since operators have complete access to the CSCW system during accidents, appropriate corrective actions could be taken to preclude the onset of unacceptable control structure temperatures. Therefore, a 2% reduction in diesel speed will not affect the CSCW system's capability of maintaining a "mild" environment in the control structure.

2) Unit 2 DX Units

Area cooling for the Unit 2 emergency switch-gear rooms and load center areas is provided by the skid mounted direct expansion units (DX units) which reject heat to the ESW system. There are two independent units which are powered from independent diesels and supplied by separate loops of ESW. With two independent units, the uncertainty induced by the potential for a 2% reduction in diesel speed is actually 1.42%, as discussed above.

Unlike other chilled water systems at SSES, these units do not operate in a "load-following" mode. At steady state operating conditions, they are capable of removing a heat load of approximately 40 tons with an ESW supply temperature of 97°F.[18,19] However, the heat load in the areas these units serve is on the order of approximately 32 tons.[19] Although a 2% reduction in diesel speed could potentially affect the capacity of the DX units, there is sufficient margin between the rated capacities of these units and their worst case accident heat load. Therefore, the potential for a 2% reduction in diesel speed will not affect adequate cooling of the Unit 2 emergency switch gear rooms.

3) Reactor Building HVAC (ECCS Room Coolers)

The performance of the reactor building room coolers could potentially be affected by a 2% reduction in diesel speed since they would be supplied with a lower ESW flow, and fan speed would be reduced by 2%. However, adequate cooling for the affected areas is nonetheless assured as discussed below:

RHR & Core Spray

Each division of RHR and Core Spray has two 50% capacity fan/cooling units. Since each fan unit is supplied by separate diesels, the uncertainty associated with the 2% diesel allowance band is actually 1.42%.

The design basis ESW flow to the RHR and Core Spray fan units is 120 GPM and 36 GPM respectively.[8] However, calculations performed in support of the Appendix "R" Program have indicated that acceptable room temperatures (i.e., design basis temperatures) are maintained with flows as low as 50 GPM for RHR and 14 GPM for Core Spray.[20] It is therefore evident that a significant amount of cooling margin exists for these coolers. In addition, it is noteworthy to add that the maximum area temperatures for these rooms does not occur until 30 days after the start of an accident.[19] Therefore, if diesel speed were to be reduced by 2%, any unusual conditions would be slow to evolve and there would be ample time to allow for proper operator response. It is therefore concluded that the potential for a reduction in both ESW and fan flow which results from a 2% lower speed would not result in unacceptable temperatures for the affected areas.

HPCI & RCIC

The HPCI and RCIC rooms are provided with two 100% capacity fan/cooling units, each of which is powered from a separate diesel and supplied by a separate loop of ESW. As with the RHR & Core Spray Coolers, their performance could be affected, since they could potentially be supplied with a lower ESW flow, and the fans speed could be reduced by 2%.

Calculations have demonstrated that under large break DBA scenarios, these coolers are not required to maintain acceptable area temperatures, since the HPCI & RCIC systems isolate under these conditions.[19] For small break scenarios, these coolers are only required if the barometric condenser piping is assumed to fail.[19,21] For scenarios during which the systems are assumed to operate, the primary heat load in these rooms therefore results from a pipe break outside containment with a small break LOCA inside containment. During these scenarios, peak area temperatures do not occur until several hours after the start of the event. At this point, it is likely that the vessel would be depressurized and high pressure make-up systems would no longer be required. Even under the worst case postulated scenarios, peak temperatures do not occur until a point when the systems would no longer be required. Therefore, even if area cooling was affected by the slower diesel speed, this would not impact the ability of the HPCI and RCIC system to perform their design intended function during the postulated scenarios.

4) The Stand-By Gas Treatment System

The Stand-By Gas Treatment System (SBGT) consists of two 100% capacity independent filter trains and fans which are supplied from separate diesels. Under

accident conditions, the system auto-initiates and takes suction from the unit-common reactor building recirculation plenum. Since each fan unit is independent, the uncertainty in system performance associated with the 2% allowance band is 1.42%.

The primary functions of the SBGT system are to: 1) establish a negative pressure of 0.25" H_2O in the secondary containment upon system initiation (i.e., draw-down phase); and 2) maintain this pressure to prevent un-monitored effluvium from reactor building leakage pathways. In performing its design function, the SBGT system assures that gaseous effluents are filtered and monitored, and maintains off-site doses below 10CFR100 limits. While a 2% reduction in diesel speed would result in lower fan flows, this reduction in system performance is not expected to impact off-site doses.

Upon initiation, SBGT is required to "draw-down" secondary containment to -0.25" H_2O in 3 minutes. Calculations have indicated that with the maximum allowable reactor building in-leakage of 4000 SCFM,[9b] a single SBGT fan can draw-down Zones I, II, & III in 142 seconds. Thus a 38 second, or 21% margin exists.[22] In addition, another calculation has shown that even with a 13 minute draw-down time, there is virtually no change in calculated off-site doses.[23] Thus, even if the system required an additional 10 minutes to draw-down the reactor building, there are no consequences with respect to off-site doses. In any case, it is reasonable to conclude that a 2% reduction in fan speed would not prevent the SBGT system from establishing -0.25" H_2O reactor building pressure prior to the propagation of fission products into the secondary containment

In the longer term phase of system operation, SBGT must maintain a -0.25" H_2O pressure in secondary containment. This is achieved by maintaining a constant SBGT system flow of 10,100 SCFM, which is drawn from two sources: an outside air supply, and the reactor building recirculation plenum. Modulating dampers control the flows from both the recirculation plenum and the outside air source, such that the reactor building is maintained at -0.25" H_2O. Since the maximum allowable reactor building in-leakage is only 4,000 SCFM, it follows that at least 6,100 SCFM must be drawn from the outside source.

The first effect of a lower fan speed would be that the fan inlet dampers, which control to maintain a constant flow of 10,100 SCFM would open further. If the fans were unable to maintain a flow of 10,100 SCFM, the other system dampers would modulate to maintain reactor building pressure by drawing less flow from the outside supply source. As a result of the large margin between the maximum reactor building in-leakage (4,000 SCFM), and the rated fan flow (10,100 SCFM), it is concluded that a 2% reduction in fan speed would not prevent the SBGT system from achieving its long term design basis objective.

IV) <u>CONCLUSION</u>

As a result of existing calibration procedures and practices, as well as the accuracy of the diesel generator electronic governor, it is unlikely that the diesel speed would deviate from 60 Hz. However, the above evaluation qualitatively considers the effects of a 2% diesel

speed reduction on large mechanical components and systems. The following summarizes these effects:

- As a result of equipment/system redundancy, the actual uncertainty in equipment speed which results from the potential for a 2% lower diesel speed is, in actuality, less than 1%.

- With respect to the short term plant response during accidents and transients: It was demonstrated that **an actual 2% reduction in diesel speed does not adversely affect: 1) the ability to establish sub-critical core conditions; 2) the ability to maintain and protect the reactor vessel pressure boundary; and, 3) provide adequate make-up capability during design basis accidents and/or transients.**

- With respect to the long term plant response during accidents and transients: It was demonstrated that as the result of the redundancy and independence of plant components, as well as conservative design practices, **an actual 2% reduction in equipment speed would not adversely affect the ability to mitigate these events, and will not result in off-site doses in excess of 10CFR100 limits.**

In summary, past and present engineering practices which govern the design and licensing bases of SSES provide for an extremely conservative and safe plant design. These practices mandate many engineering conservatisms (i.e., assumptions, inputs, methodologies, etc.) which are applied in the design of systems and also in the evaluation of specific licensing basis events. As a result of these conservatisms, many of which are mandated by regulatory requirements/commitments, a high level of system and component "over-design" establishes an ample margin of plant safety. As a result of this margin, it is not an appropriate licensing basis requirement that an additional 2% penalty be incurred due to the allowance in emergency diesel generator speed.

See page 34a for EPU and additional discussion

V) REFERENCES

1) SSES Improved Technical Specification (ITS) SR 3.8.1.7, 3.8.1.9, & 3.8.1.11 - Electrical Power Systems Surveillance Requirements
2) "Radiation Detection and Measurement", Knoll, Glenn F., John Wiley & Sons, Inc., 1979
3) EC-PUPC-1009, Rev. 0, "Evaluation Of Susquehanna Anticipated Transient With SCRAM Performance For Power Uprate Conditions" (GE Report GENE-637-024-0893, 9/93)
4) EC-049-0515, Rev. 0, "Throttling Requirements For HV-1/251F024A/B"
5) FF105620, Sheet 4401, Rev. 1, "Pump Test Data Serial Number 731-S-1152" (RHR SW 1P506A)
6) OP-116-001, Rev. 22 & OP-216-001, Rev. 19, "RHR Service Water System"
7) EC-049-1001, Rev. 2, "RHR Heat Exchanger Performance At 7850 and 8000 GPM RHRSW Flowrate"
8) EC-054-0537, Rev. 4, "Emergency Service Water System Heat Load & Flow Requirements For Uprated Power Conditions"

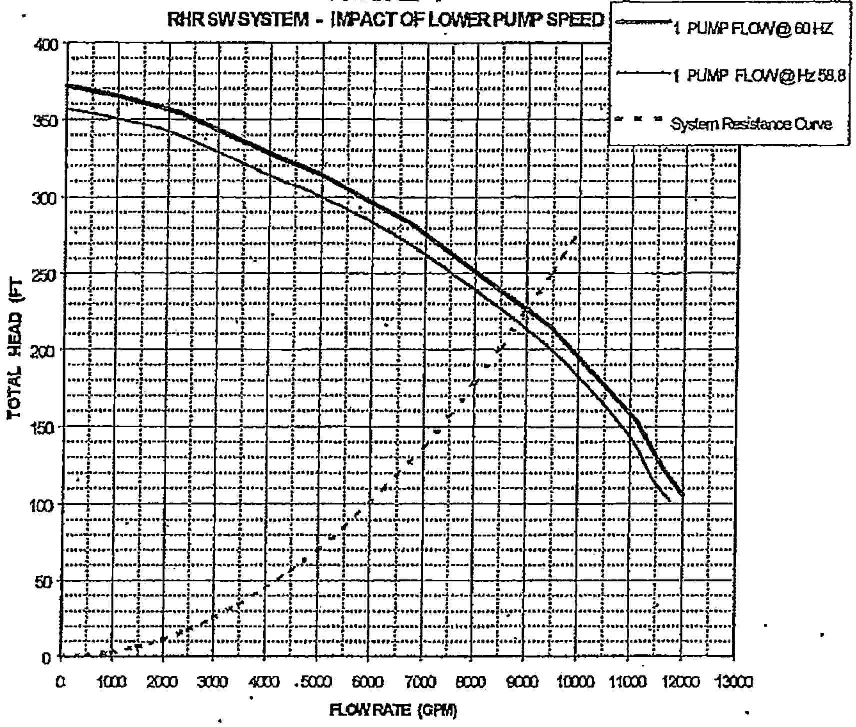
9) SSES Current Technical Specifications (CTS):
    a) 4.7.1.3.a Ultimate Heat Sink Average Temperature (Also Reference Technical Specification Interpretations (TSI) 1-97-004 & 2-97-004)
    b) 4.6.5.1.c Secondary Containment 18 Month Test Requirements
    c) 4.6.5.3.b Stand-By Gas Treatment System 18 Month Test Requirements
    d) 4.1.5.a.2 Stand-By Liquid Control System (Figure 3.1.5-2 Sodium Pentaborate Concentration)
10) EC-016-1002, Rev. 3, "Ultimate Heat Sink, Minimum Heat Transfer Design Basis Analysis - Operation With A Failed Open Loop Bypass Valve"
11) TP-054-076, Rev. 3, "ESW Loop A & B Flow Balance"
12) FF105610, Sheet 4701, Rev. 1, "Pump Test Data Serial Number 741-S-1320" (ESW 0P504A)
13) SSES Design Basis Document DBD013, "Diesel Generators and Auxiliaries"
14) EC-030-0506, Rev. 0, "Generate Performance Curves For Control Structure Chiller"
15) EC-030-1007, Rev. 1, "Transient Temperature Response Of Control Structure Rooms With HVAC Normal & Accident Conditions"
16) EC-030-0514, Rev. 1, "Power Uprate System Impact Review Control Structure HVAC & Chilled Water System"
17) IOM-168, Rev. 20, "Operating Instructions For Carrier Centrifugal Refrigeration Machines"
18) IOM-662, Rev. 12, "Refrigeration System For Unit 2 Emergency Switch-gear Room Cooling"
19) EC-LOCA-0500, Rev. 2, "COTTAP Analysis Reactor Bldg. Post Design Basis Accident Temperature"
20) EC-034-0551, Rev. 2, "Secondary Containment Thermal Response To An Appendix R Fire"
21) EC-EQQL-0695, Rev. 0, "Determination Of Room Pressure & Temperature Response To High Energy Line Break"
22) EC-070-0526, Rev. 0, "SGTS Draw-down Analysis"
23) EC-RADN-1032, Rev. 0, "Evaluation Of Offsite & Control Room Dose Consequences For Standby Gas Treatment System Single Failure Events"
24) PL-NF-98-007(P), Rev. 0 ~~(DRAFT),~~ "Susquehanna SES - Measurement Uncertainties In Appendix "K" LOCA Analyses", 5/98
25) PLA-3171, "Susquehanna Steam Electric Station - Anticipated Transient Without SCRAM"
26) SC-153-101, Rev. 6 & SC-253-101, Rev. 10, "Chemistry Surveillance Of Unit 1(2) Standby Liquid Control System"

Discussion of OE 31798 (AR 1296983)

Discussion: AR/CR 1302108 was generated to document the applicability of the OE to SSES and CRA 1307834 was generated to update this calculation. Clinton Power Station generated OE31798 (AR 1296983) which documented that power uprate significantly reduced the available ECCS margin for the containment analysis. This margin had previously been used to address lower diesel frequencies as allowed by the Technical Specifications. The main concern is that the Clinton uncertainty analysis did not specifically address the containment cooling functions of the RHR pumps. The PPL analysis in EC-024-1014 Attachment 2 section D specifically addresses the containment analysis. This section was not specifically updated for EPU.

A review of EC-PUPC-20601 determined that the power requirements for safety related systems post-EPU have remained the same. Additionally, a review of each specific section of the Attachment 2 analysis determined that although some of the details have changed slightly the conclusions of each section remain the same for EPU. Since the containment analysis is specifically mentioned in the OE that issue is discussed. As stated in the Attachment 2 section D, the RHR pumps are assumed to have a flow rate of 10,000 gpm through the heat exchanger. This is significantly below the RHR pump capacity and with a 2% reduction in frequency this flow rate will still be met. EC-PUPC-20400 evaluates containment pressure and temperature response for EPU. The analysis calculated an acceptable response even without containment sprays. Additionally, a review of EC-PUPC-20400 determined that running all 4 RHR and all 4 Core Spray pumps is conservative from a containment heat-up perspective since all these pumps add heat to the containment. If the pump speed is reduced by 2% this will reduce the pump heat load within containment which would lower suppression pool temperatures. This is conservative. So based on the specific analysis for SSES, EPU did not impact the margin for these systems as it related to the diesel frequency issue. The other concern would be equipment cooling (RHR room coolers, diesel cooling DX unit, etc.). The peak spray pond temperature did not change as a result of EPU (still 97°F) and the discussion for each of these cooling systems is still applicable. Based on this evaluation, the concerns of OE 31798 have been effectively evaluated for SSES and the conclusions remain acceptable.

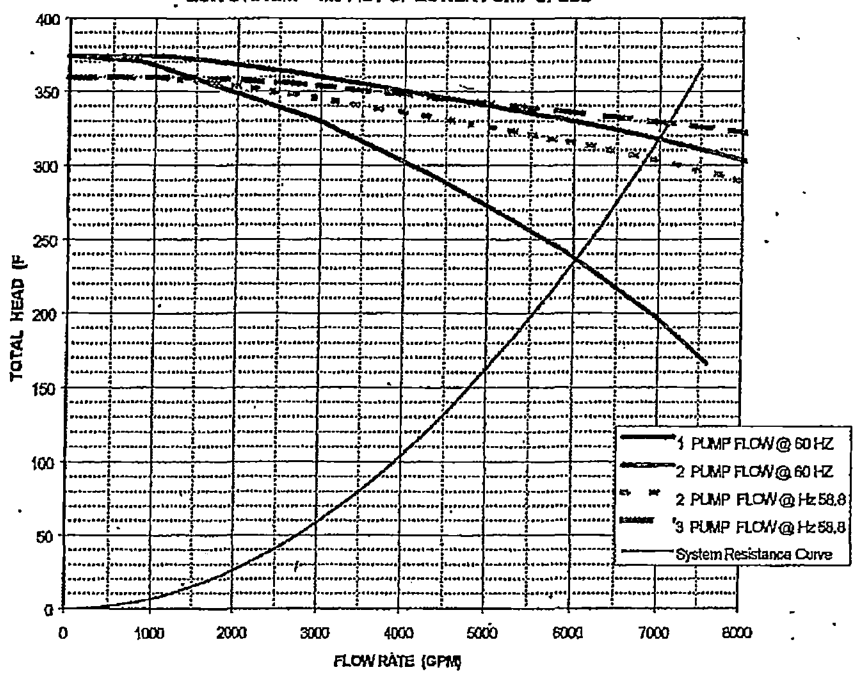
FIGURE 1


RHR SW SYSTEM - IMPACT OF LOWER PUMP SPEED
1 PUMP FLOW@ 60 HZ
1 PUMP FLOW@ Hz 58.8
System Resistance Curve
TOTAL HEAD (FT
FLOW RATE (GPM)
400
350
300
250
200
150
100
50
0
0 1000 2000 3000 4000 5000 6000 7000 8000 9000 10000 11000 12000 13000

Effects of 2% Frequency Variation on Plant Systems and Components

FIGURE 2

ESW SYSTEM - IMPACT OF LOWER PUMP SPEED



Attachment 3

EC-024-1014
Page 41

Issue:

Calculation EC-024-1014 considers the impact of the tech spec allowable +/- 1.2 Hz frequency variation on the connected loads. However, a review of the calculation did not show that the impact of higher frequency on starting torque was addressed. Flux is inversely related to speed. So an increase in speed decreases motor field flux. This in turn impacts the motor's starting torque. It appears that this impact needs to be addressed in a calculation.

Response:

A detailed review of the calculation shows discussion of MG 2 requirements which state that motors will operate successfully under running conditions at rated load with frequency variations of up to +/-5 percent, voltage variations up to +/-10 percent, and voltage and frequency variations summed by absolute value of +/-10 percent. However, a review of MG 2 shows that the referenced section in MG 2 refers to **running** loads. In MG 2, the 10/1981 version, the discussion of **starting torque** is generic but notes that the torque developed by the motor at any speed is proportional to voltage squared and inversely proportional to frequency.

For the 4 KV safety related motors, GE specifications apply for the RHR and CS motors, and E112 applies to the Bechtel scope of supply. **The specifications do not reference MG 2, but instead reference MG 1.**

The motor specs for RHR (GE 21A9369AZ), Core Spray (GE 21A9369AY) and E112 for the Bechtel scope of supply all reference MG 1 requirements for torque. Specification E112 specifically references MG 1-20.45. The number 20.45 is a section/paragraph within MG 1.

The requirements relevant to the problem statement are in MG 1-20.45 which states that the motor shall be capable of starting and accelerating a load with a torque characteristic and inertia value not exceeding that listed in MG 1-20.42 with voltage and frequency variations specified in Par. A of MG 1-20.45. Par. A allows frequency variations of up to +/-5 percent, voltage variations up to +/-10 percent, and voltage and frequency variations summed by absolute value of +/-10 percent.

The inertia values for the RHR and Core Spray motor (respectively 3960, 420 wk^2). determined by MPR in developing dynamic motor models are below the inertia values provided in MG 1-20.42 (16780, 2514 wk^2).

It can be concluded that adequate starting and accelerating torque would be available at a frequency of 60 +1.2 = 61.2 hertz.

Relevant pages of MG 1 and MG 2 follow:

Att. 3

MG 1-20.42 Load Wk^2 for Polyphase Squirrel-cage Induction Motors

The following table lists load Wk^2 which polyphase, squirrel-cage motors having performance characteristics in accordance with Part 20 can accelerate without injurious temperature rise under the following conditions:

1. Applied voltage and frequency within the limits set in MG 1-20.45.
2. During the accelerating period, the connected load torque shall be equal to, or less than, a torque which varies as the square of the speed and is equal to 100 percent of full-load torque at rated speed.
3. Two starts in succession (coasting to rest between starts) with the motor initially at ambient temperature or one start with the motor initially at a temperature not exceeding its rated load operating temperature.

	Speed, Rpm											
	3600	1800	1200	900	720	600	514	450	400	360	327	300
Hp	Load Wk^2 (Exclusive of Motor Wk^2), Lb-ft²											
100	...	...	...	...	...	...	...	12670	16830	21700	27310	33690
125	...	...	...	...	...	...	...	15610	20750	26760	33680	41550
150	...	...	...	...	...	...	13410	18520	24610	31750	39960	49300
200	...	...	...	...	...	12060	17530	24220	32200	41540	52300	64500
250	...	...	...	...	9530	14830	21560	29800	39640	51200	64400	79500
300	...	...	...	6540	11270	17550	25530	35300	46960	60600	76400	94300
350	...	...	...	7530	12980	20230	29430	40710	54200	69900	88100	108800
400	...	...	4199	8500	14670	22870	33280	46050	61300	79200	99800	123200
450	...	...	4666	9460	16320	25470	37090	51300	68300	88300	111300	137400
500	...	...	5130	10400	17970	28050	40850	56600	75300	97300	122600	151500
600	443	2202	6030	12250	21190	33110	48260	66800	89100	115100	145100	179300
700	503	2514	6900	14060	24340	38080	55500	76900	102600	132600	167200	206700
800	560	2815	7760	15830	27440	42950	62700	86900	115900	149800	189000	233700
900	615	3108	8590	17560	30480	47740	69700	96700	129000	166900	210600	260300
1000	668	3393	9410	19250	33470	52500	76600	106400	141900	183700	231800	286700
1250	790	4073	11380	23390	40740	64000	93600	130000	173600	224800	283900	351300
1500	902	4712	13260	27350	47750	75100	110000	153000	204500	265000	334800	414400
1750	1004	5310	15060	31170	54500	85900	126000	175400	234600	304200	384600	476200
2000	1096	5880	16780	34860	61100	96500	141600	197300	264100	342600	433300	537000
2250	1180	6420	18440	38430	67600	106800	156900	218700	293000	380300	481200	596000
2500	1256	6930	20030	41900	73800	116800	171800	239700	321300	417300	528000	655000
3000	1387	7880	23040	48520	85800	136200	200700	280500	376500	489400	620000	769000
3500	1491	8700	25850	54800	97300	154800	228600	319900	429800	559000	709000	881000
4000	1570	9450	28480	60700	108200	172600	255400	358000	481600	627000	796000	989000
4500	1627	10120	30890	66300	118700	189800	281400	395000	532000	693000	881000	1095000
5000	1662	10720	33160	71700	128700	206400	306500	430800	581000	758000	963000	1198000
5500	1677	11240	35280	76700	138300	222300	330800	465800	628000	821000	1044000	1299000
6000	...	11690	37250	81500	147500	237800	354400	499500	675000	882000	1123000	1398000
7000	...	12400	40770	90500	164900	267100	399500	565000	764000	1001000	1275000	1590000
8000	...	12870	43790	98500	181000	294500	442100	628000	850000	1114000	1422000	1775000
9000	...	13120	46330	105700	195800	320200	482800	685000	931000	1223000	1563000	1953000
10000	...	13170	48430	112200	209400	344200	520000	741000	1009000	1327000	1699000	2125000
11000	...	...	50100	117900	220000	366700	556200	794000	1084000	1428000	1830000	2291000
12000	...	...	51400	123000	233500	387700	590200	844800	1155000	1524000	1956000	2452000
13000	...	...	52300	127500	244000	407400	622400	893100	1224000	1617000	2078000	2608000
14000	...	...	52900	131300	253600	425800	652800	934200	1289000	1707000	2195000	2758000
15000	...	...	53100	134500	262400	442900	681500	983100	1352000	1793000	2309000	2904000

The values of Wk^2 of connected load given in the foregoing table were calculated from the following formula:

$$\text{Load } Wk^2 = A\left[\frac{Hp^{.95}}{\left(\frac{Rpm}{1000}\right)^{2.4}}\right] - 0.0685\left[\frac{Hp^{1.5}}{\left(\frac{Rpm}{1000}\right)^{1.8}}\right]^{*}$$

Where A—24 for 300 to 1800 rpm, inclusive, motors
A—27 for 3600 rpm motors

* This formula may not be applicable to ratings not included in the above table. Consult the manufacturer for the ratings which are not shown.

Authorized Engineering Information 11-12-1953, revised 6-1-1959; 7-13-1967; 5-17-1971; 11-8-1973.

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MG 1-20.43 Number of Starts

A. Squirrel-cage induction motors shall be capable of making the following starts, providing the Wk^2 of the load, the load torque during acceleration, the applied voltage, and the method of starting are those for which the motor was designed:

1. Two starts in succession, coasting to rest between starts, with the motor initially at ambient temperature, or
2. One start with the motor initially at a temperature not exceeding its rated load operating temperature.

NEMA Standard 6-1-1959.

B. If additional starts are required, it is recommended that none be made until all conditions affecting operation have been thoroughly investigated and the apparatus examined for evidence of excessive heating. It should be recognized that the number of starts should be kept to a minimum since the life of the motor is affected by the number of starts.

C. When requested by the purchaser, a separate starting information plate will be supplied on the motor.

Authorized Engineering Information 6-1-1959, revised 11-12-1970.

MG 1-20.44 Overspeeds

Squirrel-cage and wound-rotor induction motors shall be so constructed that, in an emergency, they will withstand without mechanical injury overspeeds above synchronous speed in accordance with the following:

Synchronous Speed, Rpm	Overspeed, Percent of Synchronous Speed
1801 and over	20
1800 and below	25

NEMA Standard 5-17-1955.

MG 1-20.45 Variations from Rated Voltage and Rated Frequency

A. Running

Motors shall operate successfully under running conditions at rated load with a variation in the voltage or the frequency up to the following:

1. Plus or minus 10 percent of rated voltage, with rated frequency.
2. Plus or minus 5 percent of rated frequency, with rated voltage.
3. A combined variation in voltage and frequency of plus or minus 10 percent (sum of absolute values) of the rated values, provided the frequency variation does not exceed plus or minus 5 percent of rated frequency.

Performance within these voltage and frequency variations will not necessarily be in accordance with the standards established for operation at rated voltage and frequency.

B. Starting

Motors shall start and accelerate to running speed a load which has a torque characteristic and an inertia value not exceeding that listed in MG 1-20.42 with the voltage and frequency variations specified in par. A. For loads with other characteristics, the starting voltage and frequency limits may be different.*

NEMA Standard 11-15-1956, revised 3-14-1963; 11-12-1970.

*The limiting values of voltage and frequency under which a motor will successfully start and accelerate to running speed depend on the margin between the speed-torque curve of the motor at rated voltage and frequency and the speed-torque curve of the load under starting conditions. Since the torque developed by the motor at any speed is approximately proportional to the square of the voltage and inversely proportional to the square of the frequency, it is generally desirable to determine what voltage and frequency variations will actually occur at each installation, taking into account any voltage drop resulting from the starting current drawn by the motor. This information and the torque requirements of the driven machine define the motor-speed-torque curve, at rated voltage and frequency, which is adequate for the application.

NOTE—Induction motors to be operated from solid-state or other types of variable-frequency and/or variable-voltage power supplies for adjustable-speed-drive applications may require individual consideration to provide satisfactory performance. Especially for operation below rated speed, it may be necessary to reduce the motor torque load below the rated full-load torque to avoid overheating the motor. The motor manufacturer should be consulted before selecting a motor for such applications.

Authorized Engineering Information 3-14-1963; revised 7-16-1969; 11-12-1970.

MG 1-20.46 Routine Tests

1. Measurement of winding resistance
2. No-load readings of current and speed at normal voltage and frequency. On 50-hertz motors, these readings may be taken at 60 hertz if 50 hertz is not available. On motors furnished without complete shaft and bearings, this test will not be taken.
3. Measurement of open-circuit voltage ratio on wound-rotor motors.
4. High-potential test in accordance with MG 1-20.47.

NEMA Standard 11-14-1957.

MG 1-20.47 High-potential Tests

A. Safety Precautions and Test Procedure

See MG 1-3.01.

B. Test Voltage—Primary Windings

The test voltage shall be an alternating voltage whose effective value is 1000 volts plus twice the rated voltage of the machine.*

C. Test Voltage—Secondary Windings of Wound Rotors

The test voltage shall be an alternating voltage whose effective value is 1000 volts plus twice the maximum voltage which will appear between slip rings on open-circuit with rated voltage on the primary and with the rotor either at standstill or at any speed and direction of rotation (with respect

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Insulation Class	Typical Total Winding Temperature 1.15 Service Factor	1.0 Service Factor
Class H	—	180 C
Class F	165 C	155 C
Class B	140 C	130 C
Class A	115 C	105 C

The rotor surface temperature of squirrel-cage induction motors cannot be accurately measured on production units. The rotor surface temperature varies greatly with enclosure type, cooling method, insulation class, and slip, but may be in the range of 150-225 C for Class B or Class F insulated normal slip motors when operating at rated load and in a 40 C ambient temperature.

The above insulated winding temperature and rotor surface temperature values are typical values based on continuous operation at rated voltage and rated frequency under usual service conditions. Margin for voltage and frequency variations, manufacturing variation, overload, or hot start and acceleration is not included. The motor manufacturer should be consulted for further information.

When motor-mounted space heaters are to be furnished, it is recommended that the exposed surface temperature be limited to 80 percent of the ignition temperature of the gas or vapor involved with rated space heater voltage applied and the motor deenergized.

The range of ignition temperatures is so great and variable that it is not practical for the motor manufacturer to determine if a given motor is suitable for a Division 2 area. The user's knowledge of the area classification, the application requirements, the insulation system class, and past experience are all factors which should be considered by the user, his consultant, or others most familiar with the details of the application involved when making the final decision.

Authorized Engineering Information 9-7-1977.

MG 2-3.06 PROPER SELECTION OF APPARATUS

Motors and generators should be properly selected with respect to their usual or unusual service conditions, both of which involve the environmental conditions to which the machine is subjected and the operating conditions. Machines conforming to Parts 1 and 2 of this publication are designed for operation in accordance with their ratings under usual service conditions. Some machines may also be capable of operating in accordance with their ratings under one or more unusual service conditions. Definite-purpose or special-purpose machines may be required for some unusual conditions.

Service conditions, other than those specified as usual, may involve some degree of hazard. The additional hazard depends upon the degree of departure from usual operating conditions and the severity of the environment to which the machine is exposed. The additional hazard results from such things as overheating, mechanical failure, abnormal deterioration of the insulation system, corrosion, fire and explosion.

Although past experience of the user may often be the best guide, the manufacturer of the driven or driving equipment and/or the motor and generator manufacturers should be consulted for further information regarding any unusual service conditions which increase the mechanical or thermal duty of the machine and, as a result, increase the chances for failure and consequent hazard. This further information should be considered by the user, his consultants, or others most familiar with the details of the application involved when making the final decision.

Authorized Engineering Information 11-16-1972.

MG 2-3.07 VARIATION FROM RATED VOLTAGE AND RATED FREQUENCY

A. Induction Motors

1. *Running*—Motors will operate successfully under running conditions at rated load with a variation in the voltage or the frequency up to the following:

a. Plus or minus 10 percent of rated voltage with rated frequency.

b. Plus or minus 5 percent of rated frequency with rated voltage.

c. A combined variation in voltage and frequency of plus or minus 10 percent (sum of absolute values) of the rated values, provided the frequency variation does not exceed plus or minus 5 percent of rated frequency.

Performance within these voltage and frequency variations will not necessarily be in accordance with the standards established for operation at rated voltage and frequency.

2. *Starting*—The limiting values of voltage and frequency under which a motor will successfully start and accelerate to running speed depend on the margin between the speed-torque curve of the motor at rated voltage and frequency and the speed-torque curve of the load under starting conditions. Since the torque developed by the motor at any speed is approximately proportional to the square of the voltage and inversely proportional to the square of the frequency, it is generally desirable to determine what voltage and frequency variations will actually occur at each installation, taking into account any voltage drop resulting from the starting current drawn by the motor. This information and the torque requirements of the driven machine define the motor-speed-torque curve, at rated voltage and frequency, which is adequate for the application.

NOTE—If induction motors are to be operated from solid-state or other type of variable-frequency and/or variable-voltage power supplies for adjustable-speed-drive applications, each application should be individually considered to provide satisfactory performance. Especially for operation below rated speed, it may be necessary to reduce the motor torque load below the rated full-load torque to avoid overheating the motor. The motor manufacturer should be consulted before selecting a motor for such applications.

B. Synchronous Motors

1. *Running*—Motors will operate successfully in synchronism, rated exciting current being maintained, under running conditions at rated load with a variation in the voltage or the frequency up to the following:

   a. Plus or minus 10 percent of rated voltage with rated frequency.

   b. Plus or minus 5 percent of rated frequency with rated voltage.

   c. A combined variation in voltage and frequency of plus or minus 10 percent (sum of absolute values) of the rated values, provided the frequency variation does not exceed plus or minus 5 percent of rated frequency.

Performance within these voltage and frequency variations will not necessarily be in accordance with the standards established for operation at rated voltage and frequency.

2. *Starting*—The limiting values of voltage and frequency under which a motor will successfully start and synchronize depend upon the margin between the locked-rotor and pull-in torques of the motor at rated voltage and frequency and the corresponding requirements of the load under starting conditions. Since the locked-rotor and pull-in torques of a motor are approximately proportional to the square of the voltage and inversely proportional to the square of the frequency, it is generally desirable to determine what voltage and frequency variation will actually occur at each installation, taking into account any voltage drop resulting from the starting current drawn by the motor. This information and the torque requirements of the driven machine determine the values of locked-rotor and pull-in torque at rated voltage and frequency that are adequate for the application.

NOTE—If synchronous motors are to be operated from solid-state or other types of variable-frequency power supplies for adjustable-speed-drive applications, each application should be individually considered to provide satisfactory performance. Especially for operation below rated speed, it may be necessary to reduce the motor torque load below the rated full-load torque to avoid overheating the motor. The motor manufacturer should be consulted before selecting a motor for such application.

C. Synchronous Generators

Synchronous generators will operate successfully at rated kVA, frequency, and power factor with a variation in the output voltage up to plus or minus 5 percent of rated voltage.

Performance within these voltage variations will not necessarily be in accordance with the standards established for operation at rated voltage.

D. Direct-current Motors

Direct-current motors will operate successfully using the power supply selected for the basis of rating up to and including 110 percent of rated direct-current armature voltage provided the highest rated speed is not exceeded. Direct-current motors rated for operation from a rectifier power supply will operate successfully with a variation of plus or minus 10 percent of rated alternating-current line voltage.

Performance within this voltage variation will not necessarily be in accordance with the standards established for operation at rated voltage. For operation below base speed, see MG 2-3.10.

Authorized Engineering Information 11-16-1972.

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Issue:

EC-024-1014 states that induction motors at SSES were specified to have a service factor of 1.15. This is true of the motors purchased to E112, but not true for the RHR and Core Spray motors which have a service factor of 1.0. The comment is made with regards to the horsepower (HP) demanded from the motor by the pump at a higher generator frequency which results in higher pump speed. Per the pump affinity laws, HP is proportional to the cube of the speed. The calculation assumes some increase in motor slip and uses an increase of 6 percent power demand in response to a 2% DG steady state frequency increase.

RHR Response:

For the RHR pump, the GE purchase spec 21A9369AZ specifies a maximum brake HP for the load of 1800. The RHR is a 2000 HP motor. Since the motor rating is based on output power, this is more than sufficient margin to allow an 8% load increase which is the maximum postulated increase if no increase in slip is assumed (1800*1.08 = 1944 HP)

The RHR relay setting calc EC-SOPC-0503 uses the motor Full Load Amperes (FLA) as the basis of the time overcurrent trip, time overcurrent alarm, and instantaneous overcurrent trip. Since FLA is based on the rated 2000 HP. Therefore the relay setting values are not impacted by the issue.

Since the motor is being operated within its specified values, this issue is resolved for RHR.

Core Spray Response:

For the core spray pump, the GE purchase spec 21A9369AY specifies a maximum brake HP of 690. The Core Spray is a 700 HP motor. This is less than a 6% difference.

The core spray motor data sheet shows that Full Load Amps (FLA) for the core spray motor is 90 amperes.

Operating procedures OP-151-001 and OP-251-001 specify that the core spray injection shutoff valve be throttled to limit motor amps to not exceed 90 amperes.
Since 90 amperes is the specified full load amperes, the motor is being operated within its specified values. This issue is resolved for CS.

Relevant core spray motor data sheet and procedure sections follow:

GENERAL ELECTRIC 992C302FE

VENDOR'S DRAWING REVIEW

JOB No. 8856

OUTLINE (INDUCTION MOTOR)

FIRST MADE FOR K6338PE85

NUCLEAR

E21C001A

G.E. REQ NO: 205-AD567

ITEM NO: 1

CUSTOMER: A.P.E.D. / PENN. P.&L.

ORDER NO.:

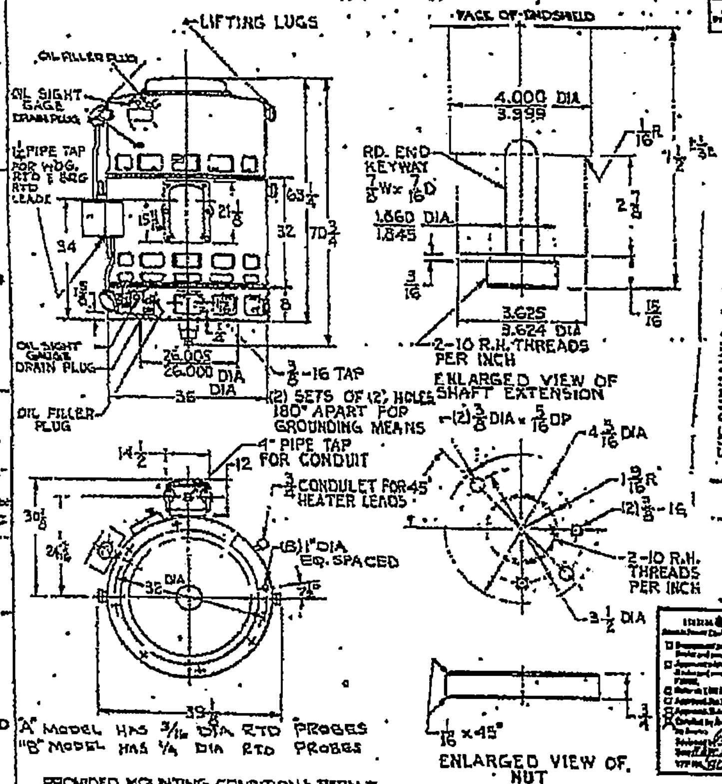
INSTALLATION SITE: SUSQUEHANNA I AND II

APPLICATION: CORE SPRAY PUMP

CUST. SPEC. NO.: 21A9369 AND 21A9369AY

SUSQUEHANNA 1, 2

MPL #E21C001A



"A" MODEL HAS 3/16 DIA RTD PROBES
"B" MODEL HAS 1/4 DIA RTD PROBES

PROVIDED MOUNTING CONDITIONS PERMIT, CONDUIT BOX MAY BE TURNED SO THAT ENTRANCE CAN BE MADE UPWARD, DOWNWARD OR FROM EITHER SIDE

MOTOR WILL START AND ACCELERATE UNDER TYPICAL PUMP LOAD WITH 80% OF RATED VOLTAGE APPLIED.

MOTOR IS DESIGNED TO CONTINUE OPERATING WHEN SUBJECTED TO A STATIC SEISMIC FORCE OF 1.5G HORIZONTALLY AND 0.5 VERTICALLY. CAPSCREWS FOR BOLTING MOTOR TO PUMP HEAD MUST BE S.A.E. 5 OR BETTER.

FOR INFREQUENT OR EMERGENCY USE AND FOR LOAD WK² NOT EXCEEDING 50% OF NEMA VALUE AND A LOAD CURVE SIMILAR TO "NA" OF A PUMP OR FAN, 2 SUCCESSIVE STARTS FROM AMBIENT TEMPERATURE, OR ONE START FROM RATED TEMPERATURE, ARE ALLOWED. FOR SUBSEQUENT STARTS ALLOW 30 MINUTES RUNNING TIME AT FULL SPEED OR 60 MINUTES IDLE TIME.

MOTOR RATING & DESCRIPTION

TYPE: SQUIRREL CAGE INDUCTION

FRAME: 6300P2 24

HORSEPOWER: 700

TIME RATING: CONTINUOUS

TEMP. RISE: 65 DEG. C

F.L. SPEED: 1780 RPM

RATED VOLTAGE: 4000 VOLTS

F.L. CURRENT: 90 AMPS

SERVICE FACTOR: 1.0

RATED FREQ.: 60 CPS

INSTRUCTION BOOK:

NO. OF PHASES: 3

CODE LETTER: G

DESIGN LETTER: —

ROTOR INERTIA: 420 LB. FT.²

APPROX. MOTOR WEIGHT 13?? LBS.

APPROX. STATOR WEIGHT 2700 LBS

WINDING TYPE: FORM COIL

INSULATION CLASS & SERVICE CONDITIONS: CLASS B VPI EPOXY-CUSTOM POLYSEAL 65° C AMBIENT

ENCLOSURE & VENTILATION: OPEN DRIPPROOF — ALL OPENINGS ARE SCREENED

MOTOR LEAD TERMINAL LUGS (INTERNAL) (3) AMP #35154 FOR #2 AWG. LEADS AND WITH HOLE FOR 3/8 BOLT

ROTATION DIRECTION: CCW LOOKING DOWN

MOTOR PERFORMANCE CHARACTERISTICS AT RATED VOLTAGE & FREQUENCY

	FULL LOAD	3/4 LOAD	1/2 LOAD
EFFICIENCY*	93.4	93.0	91
POWER FACTOR	90	89	84

*EXCLUSIVE OF .95 KW BRG. LOSS DUE TO EXTERNAL THRUST

LOCKED ROTOR CURRENT: 585 AMPS

LOCKED ROTOR P.F. (APPROX.): 22 %

LOCKED ROTOR TORQUE: 90 % F.L. TORQUE

MAXIMUM TORQUE: 200 % F.L. TORQUE

FULL LOAD TORQUE: 2060 LB. FT.

MAXIMUM ALLOWABLE STALL TIME: 14 SEC FROM 90°C OR 18 SEC FROM 30°C INITIAL TEMPERATURE

STATOR WINDING RESISTANCE - LINE TO LINE: .60 OHMS AT 25°C (APPROX.)

SPEED-TORQUE-CURRENT CURVE 385HA629

SOUND PRESSURE LEVEL 95 dBA AT 5 FT.

SOUND POWER LEVEL: 111 dBA

MOTOR BEARING & LUBRICATION DATA

	UPPER BEARING	LOWER BEARING
BEARING TYPE:	INSULATED ANGULAR CONTACT BALL	RADIAL BALL BEARING
BEARING CATALOGUE NO.:	629A230G2 (2) 7230DT	2892334P26 (NO5228)
LUBRICANT TYPE:	OIL	OIL
QUANTITY OF LUBRICANT:	40 QUARTS	5 QUARTS
RECOMMENDED LUBRICANT: OXIDATION & CORROSION INHIBITED TURBINE OIL		
WITH VISCOSITY AT 100°F	150 SUS	150 SUS
VISCOSITY AT 210°F	45 SUS	45 SUS.

THRUST BEARING RATED CAPACITY & RATED LIFE:

CONTINUOUS DOWN-THRUST: 9735 LBS. OVER 5 YEARS AVERAGE LIFE

CONTINUOUS UP-THRUST: — LBS. — HRS / PLATE BRG. - NO FATIGUE LIFE LIMIT

MAX. MOMENTARY DOWN-THRUST: [illegible] LBS.

MAX. MOMENTARY UP-THRUST: 2575 LBS.

MINIMUM ALLOWABLE CONTINUOUS DOWNTHRUST TO PREVENT DAMAGE TO GUIDE BRG. 0

MOMENTARY PERIODS OF UPTHRUST OR LIGHTER DOWNTHRUST ARE PERMISSIBLE.

THRUST BEARING COOLING WATER: — GPM — PSI MAX. (INLET) — °F MAX. (INLET)

TOTAL AXIAL ENDPLAY: .005 INCHES

MOTOR ACCESSORY EQUIPMENT DATA

SPACE HEATERS: 120 VOLT 5.46 AMPS 655 WATTS (SINGLE-PHASE)

WINDING TEMP. DEVICE: TYPE - (6) RTDS 100Ω @ 0°C PLATINUM

VOLTS — AMPS — NORMALLY OPEN CLOSED

BEARING TEMP. DEVICE: TYPE - (1) DUAL ELEMENT PLATINUM (100Ω @ 0°) RTD PER BRG

VOLTS — AMPS — NORMALLY OPEN CLOSED

FF 12650

FF 12552

SYSTEM CRITICAL REED FREQUENCY CALCULATION DATA

IN ORDER TO AVOID EXCESSIVE VIBRATION IT IS NECESSARY THAT THE REED CRITICAL FREQUENCY (CPM) OF THE MOTOR-PUMP SYSTEM BE MECHANICALLY AT LEAST 25% ABOVE OR BELOW MOTOR OPERATING SPEED (RPM); DESIGN OF COMPLETE SYSTEM (MOTOR, PUMP, FOUNDATIONS & PIPING) MUST PROVIDE FOR THIS. MOTOR DATA FOR SYSTEM CRITICAL CALCULATIONS ARE BELOW. REED CRITICAL FREQUENCY AND DEFLECTION OF MOTOR AT CENTER OF GRAVITY (C.G.) ARE SHOWN FOR MOTOR BOLTED TO A RIGID MASS AND CONSIDERED AS A HORIZONTAL CANTILEVER BEAM. DEFLECTION OF MOTOR AT C.G. IS THAT CAUSED BY WEIGHT OF MOTOR ONLY, AT STANDSTILL.

8856-M1-E21-8-6

MOTOR WEIGHT	6300	LBS
DIST. FROM MOTOR BASE TO CG.	29	INCHES
MOTOR REED CRITICAL FREQ.	2530	CPM
DEFLECTION OF MOTOR AT CG.	.0035	INCHES
SUGGESTED SYSTEM REED CRITICAL FREQ.	1350	CPM MAX.

PROPOSED DEPARTURES FROM SPECIFICATIONS

REVISIONS	PRINTS TO
	15
	8
	3
	28
	2
	16

UMBS SAN JOSE 992C302FE

992C302FE

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For Information Only

☐ g. Core Spray Room Unit Coolers 1V211A and C(B and D) **AUTO START** indicated on Heating and Ventilation Panel 1C681.

☐ h. CORE SPRAY Loop A(B) flow increases as Reactor Pressure decreases.

NOTE (1):	Placing control switch to **CLOSED** with initiation signal present and reactor pressure < 420 psig will cause White indicating light over control switch to **ILLUMINATE**. This indicates initiation signal present with operator action overriding initiation signal. This light will remain **ILLUMINATED** until initiation signal is reset even if valve returned to **FULLY OPEN** position.
NOTE (2):	In support of Emergency Operating Procedures the Core Spray System can be operated at a maximum current limit of 90 amps on the pump motor. This corresponds to a run out flow of 7900 gpm for 2 loop pumps or 3950 for 1 pump at 0 psig RPV pressure. As Suppression Pool temperature increases and level decreases, pump performance must be monitored for loss of adequate NPSH.

2.2.6 **Throttle** CORE SPRAY LOOP A(B) IB INJ SHUTOFF HV-152F005A(B) as required to support RPV level control:

☐ a. <90 amps and <7900 gpm for two pump operation (emergency operation)

☐ b. <90 amps and <3950 gpm for one pump operations (emergency operation)

<u>OR</u>

☐ c. <6350 gpm for two pump operation (non-emergency operation).

☐ d. <3175 gpm for single pump operation (non-emergency operation).

☐ g. Core Spray Room Unit Coolers 2V211A and C (B and D) **AUTO START** indicated on Heating and Ventilation Panel 2C681.

☐ h. CORE SPRAY LOOP A(B) flow increases as Reactor Pressure decreases.

NOTE (1):	**Placing** control switch to **CLOSED** with initiation signal present and reactor pressure < 420 psig will cause White indicating light over control switch to **ILLUMINATE.** This indicates initiation signal present with operator action overriding initiation signal. This light will remain **ILLUMINATED** until initiation signal is reset even if valve returned to **FULLY OPEN** position.
NOTE (2):	In support of Emergency Operating Procedures the Core Spray System can be operated at a maximum current limit of 90 amps on the pump motor. This corresponds to a run out flow of 7900 gpm for 2 loop pumps or 3950 for 1 pump at 0 psig RPV pressure. As Suppression Pool temperature increases and level decreases, pump performance must be monitored for loss of adequate NPSH.

2.2.6 **Throttle** CORE SPRAY LOOP A(B) IB INJ SHUTOFF HV-252F005A(B) as required to support RPV level control:

☐ a. < 90 amps and < 7900 gpm for two pump operation (emergency operation)

☐ b. < 90 amps and < 3950 gpm for one pump operation (emergency operation)

<u>OR</u>

☐ c. < 6350 gpm for two pump operation (non-emergency operation).

☐ d. < 3175 gpm for single pump operation (non-emergency operation).

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For Information Only

IOM 156

- Core Spray Pump >

PUMP DATA SHEET

PURCHASER	General Electric Company
USER	Pennsylvania Power And Light Company
LOCATION	Susquehanna Nos. 1 & 2 Berwick, Pennsylvania
INGERSOLL-RAND ORDER NO.	006-36051
PUMP SERIAL NUMBERS	1073-79 thru 86
PUMP APPLICATION	Core Spray Pump(s)
PUMP SIZE	25 APKD
NUMBER OF PUMP STAGES	6 (Double Suction First Stage)
PUMP RATING	3175 GPM at 1780 RPM
NET POSITIVE SUCTION HEAD REQUIRED @ 3175 GPM	4.5' (Ref. C.L.Suction)
TOTAL HEAD FEET @ 3175 GPM	668'
SUCTION PRESSURE	125 PSI (Max.)
DISCHARGE PRESSURE	500 PSI (Max.)
PUMP EFFICIENCY @ 3175 GPM	83.5%
SHAFT PACKING	Mechanical Seal
PUMP DRIVER	700 H.P. Motor with 1.0 S.F.
DRIVER MANUFACTURER	General Electric

APPROXIMATE WEIGHTS

WEIGHT OF PUMP ELEMENT AND DISCHARGE HEAD	5,560 Lbs.
WEIGHT OF THE SHELL	1,555 Lbs.
TOTAL WEIGHT OF PUMP DRY	7,115 Lbs.
WEIGHT OF WATER IN PUMP	2,500 Lbs.
WEIGHT OF MOTOR	6,300 Lbs.
WEIGHT OF TOTAL FLOOR LOAD	15,915 Lbs.
WK^2	47 Lb-ft^2

Section 3-3 of Attachment 3
PLA-7471

Evaluation of the Impact of DG Steady State Frequency and Voltage Variations Within Acceptable Limits

(For Information Only)

Excerpts of Calculation EC-024-1035
(66 pages follow)

CALCULATION REVISION DESCRIPTION SHEET
NEPM-QA-0221-2

REVISION NO: 1	CALCULATION NUMBER: EC-024-1035

☐ FULL REVISION	☐ SUPERSEDED
☒ PAGE FOR PAGE	☐ VOIDED

Revised Pages	Add	Rpl	Rmv	Description of Revision on the Listed Pages
Page 1	☐	☒	☐	Replace Calculation Cover Sheet
Page 1a	☒	☐	☐	Added Calculation Revision Description Sheet
Page 1b	☒	☐	☐	Added Technical Change Summary Page
Page 7	☐	☒	☐	Added INSERT 1 reference to Page 7a
Page 7a	☒	☐	☐	Added design basis tie between calculation and Tech Specs
Page 8	☐	☒	☐	Added INSERT 2 reference to Page 7a
	☐	☐	☐	
	☐	☐	☐	
	☐	☐	☐	
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TECHNICAL CHANGE SUMMARY PAGE
NEPM-QA-0221-5

Calculation: Number: EC-024-1035 **Revision No.** 1

This form shall be used to (1) record the Technical Scope of the revision and (2) record the scope of verification if the calculation was verified. It should not be more than one page. Its purpose is to provide summary information to the reviewer, verifier, approver, and acceptor about the technical purpose of the change. For non-technical revisions, state the purpose or reason for the revision.

Scope of Revision: Revised calculation to add statement that clarifies that this calculation provides the design basis for EDG steady state voltage and frequency and provides the basis to support changes to plant Technical Specification Section 3.8.1 surveillance requirements and their bases.

Scope of Verification (If verification applies): Verification shall be performed on INSERT 1, Page 7A to ensure that accurate design basis assertions are made and accurate reference to TS & TSB sections have been applied.

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TABLES

EXHIBITS

FIGURES

1.0 PURPOSE

The purpose of this calculation is to evaluate and determine the effects of the emergency diesel generator (EDG) frequency and voltage variations, 59.3Hz to 60.5Hz and 4000V and 4400V respectively, on the diesel loading and selected plant components fed by the diesel during a loss of coolant accident coincident with a loss of offsite power (LOCA/LOOP) on one unit (Unit 1) with forced safe shutdown on the other unit (Unit 2). A conservative bounding approach is used to evaluate loadings on EDGs A through E when operating within allowable Technical Specifications (TS) voltage and frequency ranges. This calculation will also demonstrate that EDG voltage and frequency variations within allowed TS steady state frequency and voltage ranges do not increase EDG loading above its continuous rating nor adversely impact the capability of safety related components required to perform their design function to mitigate the effects of a design basis accident. These essential safety related components fed from the DG during accident scenarios are tested and expected to operate around nominal frequency and various rated voltages. Although the DG voltage and frequency regulators are practically independent of each other, the evaluation documented herein, analyze system and component performance when the onsite power source is operating at minimum or maximum steady state frequency and voltage outside of their setting bands. This analysis is not intended to demonstrate EDG full compliance to Reg. Guide 1.9 but rather focus on the capability of the diesel to perform its safety function at steady state allowable voltage and frequency limits. By intentionally showing the full transient response, the goal is to be able to highlight the brief duration of those occasions where some RG transient requirements, when applicable, may be challenged but with the ultimate safety function capability (motor start and recovery voltage and frequency) being maintained. All RG 1.9 transient requirements are met through EDG surveillance testing.

1.1 Acceptance Criteria

AC1- The continuous loading of DG A and E at extreme voltage and frequency tolerances, 4000kW and 5000kW respectively, are greater than the sum of conservatively estimated Engineered Safety Features (ESF) loads and Non-ESF not manually initiated loads needed to be supplied following a Unit 1 design basis Accident, Unit 2 Forced Shutdown and DG B Unavailable (FSAR Table 8.3-3)

AC2- DG A and E are capable of starting and accelerating all ESF and forced shutdown loads.

AC3- DG A and E voltage and frequency are capable of recovery from transients caused by step loads increases.

AC4- The qualitative analysis results must be demonstrated to reasonably match (within ±3%) the ETAP transient analysis model results for each case. ETAP is an Appendix B software and its results are deemed more realistic since it accounts

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for the transient response of the circuits which the qualitative approach does not.

AC5- DGs operation within the allowable TS voltage and frequency ranges does not adversely impact the capability of safety related components required to perform their design functions to mitigate the effects of a design basis accident.

2.0 CONCLUSIONS

For the DG steady state frequency and voltage ranges evaluated herein(i.e. Voltage: 4000V – 4400V and Frequency: 59.3Hz – 60.5Hz), the equipment which are fed by the DG and required to mitigate the effects of a Unit 1 DBA with Unit 2 Forced Shutdown and DG B Unavailable for 60 minutes and beyond remain capable of performing their intended safety functions. Variations in loadings associated with steady state frequency and voltage changes within the aforementioned ranges will not subject the DGs to operate above their continuous ratings when supplying required ESF loads and Non-ESF not manually initiated loads for mitigation of the worst case DBA. Therefore, the evaluation performed herein demonstrates that the effects of the postulated DG steady state frequency and voltage variations do not adversely affect critical safety functions nor result in unanalyzed operating conditions.

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3.0 INPUTS

3.1. Diesel generators A, B, C, and D are rated for 4000kW continuous and 4700kW for 2000 hours while diesel generator E is rated for 5000kW continuous with a 2000 hours rating of 5500kW. (Reference 6.1.6)

3.2. Only one loop of RHRSW (Residual Heat Removal Service Water) pump running is required to remove decay heat for both units. For the purposes of demonstrating DG loading capability, the FSAR diesel loading tables show two RHRSW pumps in operation, one for the unit with a DBA (DG-C) and one for the shutdown unit (DG-A) which indicate the maximum possible RHRSW per diesel loading. (Reference 6.1.9 Note 17)

3.3. Per NEMA MG 1, AC induction machines shall successfully operate under running conditions at rated load with a variation in the voltage or the frequency up to the following:

a. ± 10 percent of rated voltage, with rated frequency
b. ± 5 percent of rated frequency, with rated voltage
c. A combined variation in voltage and frequency of 10 percent (sum of absolute values) of the rated values provided the frequency variation does not exceed ± 5 percent of rated frequency.

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This calculation, in concert with calculations EC-024-1014 and EC-024-1031, establishes the design basis for EDG steady state voltage and frequency ranges as 4000V-4400V and 59.3Hz to 60.5Hz, respectively. This provides the basis to support changes to the following Technical Specification Surveillance requirements and their associated bases as follows:

Technical Specification 3.8, Electrical Power Systems

<table>
<tr><th>Document</th><th>Sections</th><th colspan="2">Surveillance Requirements</th></tr>
<tr><td>Unit 1 Technical Specifications</td><td>Tech Spec Section 3.8.1, "AC Sources - Operating"</td><td rowspan="2">SR 3.8.1.7
SR 3.8.1.9
SR 3.8.1.11
SR 3.8.1.12
SR 3.8.1.15
SR 3.8.1.19
SR 3.8.1.20</td><td rowspan="2">Monthly Operability
Load Reject
Loss of Offsite Power (LOOP)
Loss of Coolant Accident (LOCA)
Hot Restart
LOCA/LOOP
Simultaneous Start of all four Diesels</td></tr>
<tr><td>Unit 2 Technical Specifications</td><td>Tech Spec Section 3.8.1, "AC Sources - Operating"</td></tr>
<tr><td>Unit 1 Technical Specification Bases</td><td colspan="3">TSB B3.8.1, "AC Sources - Operating", Surveillance Requirements Section</td></tr>
<tr><td>Unit 2 Technical Specification Bases</td><td colspan="3">TSB B3.8.1, "AC Sources - Operating", Surveillance Requirements Section</td></tr>
</table>

INSERT 2 (Page 8)

3.8 The method used in determining the minimum and maximum steady state output voltages, 4000V and 4400V respectively, for use in the surveillance requirements of the diesel generators as defined in Technical Specification Section 3.8.1 are derived from calculation EC-024-1031.

3.9 The method used in determining the minimum and maximum steady state frequencies, 59.3Hz and 60.5Hz respectively, for use in the surveillance requirements of the diesel generators as defined in Technical Specification Section 3.8.1 are described from calculation EC-024-1014.

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3.4. AR-2014-22916 evaluated the impact of EDG frequency and voltage variations for the lowest margin flow systems credited in the safety analysis, namely RHR (Residual Heat Removal), Core Spray (CS) and RHRSW. Per the subject evaluation, flow rates used in the LOCA analysis remain conservative even with consideration of EDG operation at minimum voltage and frequency (4000V and 59.3Hz).

3.5. The DG fuel oil consumption calculations are performed based upon fuel oil consumption rates associated with the DG continuous rating of 4000kW for DGs A through D and 5000kW for DG E. (Reference 6.4.4)

3.6. DG fuel oil transfer pump required flow rate used to evaluate the effects of DG frequency and voltage variations is provided in Attachment 9.27.

3.7. The major emergency motor loads (RHR, Core Spray, ESW, and RHRSW) are from Reference 6.1.10. These values are derived in the subject reference using for each load the pump maximum brake horsepower at any head and flow; rated voltage (4kV) and nominal frequency (60Hz) per applicable Specifications providing specific engineering and performance data requirements[1].

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4.0 DESIGN BASES

4.1 Regulatory Guide 1.9, March 10, 1971, "Selection of Diesel Generator Set Capacity for Standby Power Supplies." This Regulatory Guide is applicable to Diesel Generators A through D.

4.2 Regulatory Guide 1.9, December, 1979, "Selection, Design, and Qualification of Diesel - Generator Units Used as Standby (Onsite) Electric Power Systems at Nuclear Power Plants." This Regulatory Guide is applicable to Diesel Generator E.

4.3 The five diesel generators (A,B,C,D,E) are shared by the two units with DGs A through D normally assigned to the safety-related load groups. DG E can be substituted for any of the other four diesels (A-D) without violating the independence of the redundant safety related load groups. The capability of the aligned diesel generators is such that a loss of one of the four DGs will not impair the capability to operate the engineered safety feature loads of one unit and those systems required for concurrent safe shutdown of the second unit.

[1] See Reference 6.4.25 & 6.4.26

4.4 The four aligned DGs are automatically started and ready to accept loads within 10 seconds after the initiation of the start circuit by any of the following conditions:

a) Total loss of power at the 4.16kV Class 1E bus of either unit to which the DG is connected
b) Safety injection signal - low water in the reactor, high drywell pressure, or manual actuation.

4.5 Per FSAR 8.3.1.4.6, with one DG unavailable, the remaining three in-service DGs have the capacity to supply the required ESS loads in one unit; the equipment needed for safe shutdown of the other unit; and any more ESS loads manually switched onto the DGs as illustrated in FSAR Tables 8.3-2 through 8.3-5a. These tables represent a worst case loading based on mechanical and electrical equipment availability. The plant operators may choose to run different equipment than that specified in the tables after 10 minutes. However by procedure the loading of each DG will be maintained below its long-term continuous rating of 4000kW.

4.6 Regulatory Guide 1.108 (Rev.1) – Periodic testing of diesel generators used as onsite electric power systems at nuclear power plants.

The design basis for testing the Class 1E diesel generators is RG 1.108 (Rev.1) as described in FSAR section 14.2.7. RG 1.108, paragraph C.2.a (2) requires verification that voltage and frequency are maintained within required limits during testing.

4.7 Per FSAR 1.2.2.6.2, the general steady state design criterion for the AC electrical system is to provide voltage between 90% and 110% of the equipment rating. The Class 1E motors are specified with accelerating capability at 80% nominal voltage at their terminals (Reference FSAR 8.3.1.9).

4.8 The on-site electric power system includes four load groups. The load groups are redundant with sufficient independence to ensure that postulated single failures affect only a single load group and are limited to the extent of total loss of that load group.

5.0 ASSUMPTIONS

5.1. Affinity laws accurately predict centrifugal pump and fan performances at different state points than known ones. Most Affinity Laws' equations do not apply to positive displacement pump. 2P208 A & B – Standby Liquid Control Injection pumps A & B are positive displacement pumps which could be supplied by the diesel generators. However, they are a not active loads for the DBA scenario evaluated herein (i.e. Unit 1 DBA and Unit 2 Forced Shutdown).

Justification: This is standard methodology in the industry for centrifugal pumps and fans. No further verification required.

5.2. The LOCA/ False LOCA scenario was not analyzed due to the fact that ECCS loading for LOCA/ False LOCA is the same as LOCA on either unit 1 or unit 2 because of ECCS equipment circuit breaker interlocks. This is fully documented in Appendix B of "Nuclear Plant Engineering Technical Report No. NPE-84-002" December 1983 (Reference 6.4.11). Since separate LOCAs on Unit 1 and Unit 2 have been analyzed, the LOCA/False LOCA event is enveloped by these cases. No further verification is required

5.3. MOV loads are not included in the diesel generator loading because of their small magnitude and short duration. This is consistent with SSES methodology of assigning ESF and selected Non-ESF loads to DGs (Reference 6.1.9 Note 1). No further verification is required.

5.4. Only major induction motor loads (RHR, Core Spray, RHRSW and ESW) are explicitly evaluated and modeled for the effects of DG steady state frequency and voltage variations. Other worst case DBA accident mitigating loads are lumped together as either constant impedance or constant kVA. A power factor of 0.9 is assumed for the constant kVA. The inductive loads evaluated and modeled individually represent approximately 85% of the total ESF loads on FSAR Table 8.3-3. They are expected to have the most impact on the transient response of the DGs and they are loaded on the DGs per the load sequence governing the DBA scenario under consideration. Static load adjustments due to voltage variations are also accounted for. This approach is consistent with common practice in the industry. No further verification is required.

5.5. Diesel generator speed controller and static exciter voltage regulator (SEVR) although independent of each other, are assumed to coincidently operate erroneously outside of their respective setting bands. The Woodward Governor and SEVR systems independently control the DG speed and voltage respectively around established speed and voltage setpoint values. Coincident voltage and frequency variations would yield bounding results from a DG operation and loading perspective as failure or continuous misoperation of two control systems monitoring separate parameters is implied. This approach is consistent with some postulated scenarios described by the NRC in RAIs (i.e. RAI 10 from ML13298A781)

5.6. ESS 480 VAC load center (LC) transformer reactance and secondary voltage changes due to DG steady state frequency variations (-1.16% or 0.8%) is negligible. As such, DG output steady state frequency will carry through the LC transformer to the motor control centers (MCCs). The impedance changes due to the frequency variation percentages above are smaller than the tolerance of the specified value prescribed by IEEE C57.12.01-1998 which requires the impedance of a two-winding transformer to have a tolerance of ± 7.5%. This is

a common industry requirement applied for the manufacturing and testing of dry-type power transformers. No further verification is required.

5.7. All load values listed in FSAR Table 8.3-3 are assumed to have been determined at rated frequency (60Hz) and equipment voltage. This is validated under the methodology discussion (Exhibit 9) by deriving the kW values for RHR and Core Spray motors. Additionally, based on the methodology used to evaluate voltage and frequency impacts, this assumption yields higher DG total loading at nominal voltage and frequency. Overall, this assumption would add conservatism to the results. No further verification is required.

6.0 REFERENCES

6.1 Licensing / Regulatory

6.1.1 NRC Regulatory Guide 1.9, Rev.0, 1971 – Selection of diesel generator set capacity for standby power supplies.

6.1.2 NRC Regulatory Guide 1.9, Rev.2, 1979 – Selection, design, and qualification of diesel generator units used as standby (onsite) electric power systems at nuclear power plants.

6.1.3 FSAR 1.2.2.6.2 Rev.71, Electric Power Distribution System

6.1.4 FSAR 8.1.6.1(b) Rev.63, Regulatory Guide 1.9 (3/71)

6.1.5 FSAR 8.1.6.1(c) Rev.63, Regulatory Guide 1.9 (12/79) (Diesel Generator E Only)

6.1.6 FSAR 8.3.1.4 Rev.70 - Standby Power Supply

6.1.7 FSAR 8.3.1.9 Rev.70, " Design Criteria for Class 1E Equipment"

6.1.8 FSAR 9.5.4 Rev.66 – Diesel Generator Fuel Oil Storage and Transfer System

6.1.9 FSAR Table 8.3-1 Rev.58 – Assignment of ESF & Selected Non ESF Loads to Diesel Generators & ESS Buses

6.1.10 FSAR Table 8.3-3 Rev.57 – Diesel Generator Loading Diesel B Unavailable Unit 1 Design Basis Accident Unit 2 Forced Shutdown

6.1.11 Technical Specification 4.5.1.b.1 and 4.5.1.b.2 – Emergency Core Cooling Systems (ECCS) surveillance Requirements (Core Spray & RHR).

6.1.12 Technical Specification Surveillance Requirements 3.8.1.7, 3.8.1.9, 3.8.1.11, 3.8.1.12, 3.8.1.15, 3.8.1.19 and 3.8.1.20.

6.2 Industry Standards

6.2.1 IEEE Std. 308-1974 – Criteria for class 1E power systems for nuclear power generating stations.

6.2.2 IEEE Std. 387-1977 – Criteria for diesel generator units applied as standby power supplies for nuclear power generating stations.

6.2.3 IEEE 399-1997, - Recommended Practice for Industrial and Commercial Power Systems Analysis.

6.2.4 WCAP-17308-NP, Rev.0 – Treatment of Diesel (DG) Technical Specification Frequency and Voltage Tolerances, April 2012.

6.2.5 NEMA MG1-2007, - Motor and Generators

6.2.6 ANSI C50.41-2000, - Polyphase Induction Motors for Power Generating Stations

6.2.7 IEEE Std. C57.12.01-1998, - Requirements for Dry-Type Distribution and Power Transformers Including Those with Solid-Cast and/or Resin-Encapsulated Windings

6.2.8 Mechanical Engineering Reference Manual for the PW Exam, 11 Edition by Michael R. Lindeburg, PE

6.2.9 IEEE Std 112-1996, Test Procedure for Polyphase Induction Motors and Generators

6.3 Computer Programs

6.3.1 ETAP Version 12.0.0 N

ETAP 12.0.0N transient stability analysis module was used to determine the transient behavior and make general stability assessments of the DG and major induction motors when operating at voltage and frequency other than nominal.
The ETAP transient stability analysis program is an analytical tool designed to investigate the system dynamic responses and stability limits of a power system before, during, and after system changes or disturbances. The program allows modeling of dynamic characteristics of a power system, implements the user-defined events and actions,

solves the system network equation and machine differential equations interactively to find out system and machine responses in time domain.

In order to perform transient stability calculations, ETAP 12.0.0N transient stability analysis module utilizes a set of comprehensive methods that require knowledge of machine dynamic models and machine control system model (such as excitation system, PSS, AVR, etc...).

6.3.2 Microsoft Office 2010

6.3.2.1 Excel 2010

Microsoft Excel has been used in this calculation to extract some of ETAP simulation results, perform data plots and basic mathematical computations.

6.3.2.2 Word 2010
Microsoft word was used to perform document editing and printing.

6.3.3 Maplesoft was used to solve, based on inputs from Reference 6.4.6, various equations and generate RHRSW circuit model parameters for ETAP transient stability modeling.

6.4 SSES Calculations and Engineering Documents

6.4.1 EC-024-1014 Rev.3, Justification for ITS Diesel Generator Frequency Acceptance Limits of 60 +/- 1.2Hz.

6.4.2 EC-023-0507 Rev.4, Diesel Generator A-E Fuel Oil Day Tank Capacity

6.4.3 EC-023-0530 Rev.0, Diesel Generator Fuel Oil Storage Tank Capacity

6.4.4 EC-023-1012 Rev.2, Evaluate Impact on Use of Ultra Low Sulfur Diesel (ULSD) fuel on Diesel Generator Fuel oil Storage & Transfer System

6.4.5 EC-VALV-1171 Rev.0, Evaluation of the proposed DG steady state voltage and frequency range impact on motor operated valves.

6.4.6 EC-024-1029 Rev.0, Evaluation of EDG frequency response during design basis LOOP/LOCA transient loading with replacement Woodward 2301A governor.

6.4.7 EC-024-1030 Rev.0, EDG transient analysis models for ETAP.

6.4.8 EC-024-1031 Rev.0, DG Steady State Output Voltage for Surveillance Test in Isochronous Mode

6.4.9 EC-024-1004 Rev.0, Required Diesel Generator Lube Oil Volume for Technical Specifications

6.4.10 EC-024-0609 Rev.0, Instrument PSL03414E Created To Document Existing Setpoint Calcs That Allows Retrieval Based On Device SEIS Identification Number...

6.4.11 EC-LOCA-0511 Rev.0, Performance under loss of coolant accident and loss of offsite power. Technical Report NPE-84-002.

6.4.12 EC-004-1002, Rev 7, "LOCA Time Line Development for Plant Voltage Studies"

6.4.13 EC-004-1034, Rev.1 - Power Cable Data for ETAP

6.4.14 EC-004-1035, Rev.3 - Power Transformer Data For Input Into ETAP

6.4.15 EQAR 027 Rev.8, Drywell Unit Cooler Fan Motors & Control Rod Drive Ventilation Fan Motors

6.4.16 Specification M30 Rev.5, Design Specification for Diesel Generators

6.4.17 IOM194 Rev.16, 3 Phase Thyristor Controlled Model 3SD-260-300CE

6.4.18 IOM202 Rev. 15, 3 Phase Thyristor Controlled Model 3SD-130-100CE 125V DC 100 Ampere Battery Chargers

6.4.19 IOM183-2 Rev.92, KSV Diesel Generator & Engines

6.4.20 IOM749-1 Rev.28, IOM Emergency Standby KSV-20T Diesel Generator

6.4.21 AR-2014-22916, Impact of EDG frequency variations on pumps and fans

6.4.22 FF106080 Sh. 1001 Rev.1, Induction Motor Data Sheet Diesel Oil Transfer Pumps

6.4.23 FF103120 Sh.401 Rev.7, Outline Residual Heat Removal Service Water Pump Induction Motors 1P506A ....

6.4.24 FF103120 Sh. 202 Rev.2, Residual Heat Removal Pump Motors 1P506a 1P506B Induction Motor Data Sheet

6.4.25 Specification 21A9369AY Rev.2, Purchase Spec Data Sheet Electric Motors Vertical

6.4.26 Specification 21A9369AZ Rev.2, Purchase Spec data Sheet Electric Motors Vertical

6.4.27 SE-023-A01 Rev.7, Diesel Generator A Fuel Oil System ASME Pressure Test

6.4.28 SE-023-E01 Rev.6, Diesel Generator E Fuel Oil System ASME Pressure Test

6.4.29 IOM767 Rev.0, Fuel Oil Transfer Pump For Diesel Generator E Bldg

7.0 COMPUTATIONS AND ANALYSES

Major plant equipment fed from the diesel following a Unit 1 LOCA/LOOP and a safe shutdown of Unit 2 were evaluated to determine the effects of DG voltage and frequency variations between 4000V – 4400V and 59.3Hz – 60.5Hz respectively. DGs operation at steady state voltage and frequency other than nominal values will have an impact on the engine loading, its auxiliary systems and loads powered from the diesel. The analysis performed herein is limited to an assessment of such impact to the following:

1. Diesel Generator Lube Oil System
2. Diesel Generator Jacket Water System
3. Diesel Generator Fuel Oil Storage and Transfer System
4. Diesel Generator loading
5. Diesel Generator Fuel Oil Consumption
6. Induction Motor Operation
7. Motor-operated valves (MOVs) performance
8. Battery Chargers

Changes in the aforementioned attributes will be evaluated below to demonstrate that equipment relied upon to mitigate the effects of a design basis accident would continue to perform their safety functions as designed even with consideration of DG steady state voltage and frequency variations within allowable Tech Spec limits. DG loading list under the considered bounding scenario encompasses several large and small pumps. Only major pumps in safety significant systems are evaluated individually and the remaining loads are conservatively lumped for consideration of their aggregate impact. Table 1 below depicts the resulting load categories for the evaluated scenario[2].

[2] See Exhibit 1 & 2 for lumped loads

	Motor Loads			Static Load	
	BHP	kW	kVAR	kW	kVAR
CS	691	552	268.1	-	-
RHR	1798	1429	659.6	-	-
RHRSW	574	463	256.9	-	-
ESW	440	357	196.1	-	-
U1 Lump	-	718.8	348.1	252.6	0
U2 Lump	-	75.5	36.6	75.0	0
DGE Lump	-	135	65.4	103.5	0

Table 1: DGs A and E Loading per FSAR Tables 8.3-3 & 8.3-3a

	Motor Loads			Static Load	
	BHP	kW	kVAR	kW	kVAR
CS	691	552	268.1		
RHR	1798	1429	659.6		
RHRSW	574	463	256.9		
ESW	440	357	196.1		
U1 Lump*	-	350	169.5	156.55	
U2 ESF Loads Lumped (FSD)	-	75.5	36.6	75.0	
DGE Lump	-	135	65.4	103.5	

* U1 Lump = (Total ESF & Other Non-ESF Loads) - Unit 2 ESF Loads Lumped (FSD)

Table 2: DGs A and E Loading per FSAR Tables 8.3-3 & 8.3-3a Adjusted to Remove Manually Initiated Non-ESF Loads

DG steady state frequency variations have the direct effect of changing the speed of the motors that are fed from the subject DG. The subject changes in motor speed impact attributes such as pump flow, net positive suction head (NPSH) availability and horsepower requirements. Using the "Affinity Laws" (Reference 6.2.8), Table 3 below estimates the performance changes of these parameters when DG is operating at minimum and maximum steady state frequency of 59.3Hz and 60.5Hz respectively.

PARAMETERS	**EFFECTS OF DG MINIMUM FREQUENCY (f_{min} = 59.3Hz)**	**EFFECTS OF DG MAXIMUM FREQUENCY (f_{max} = 60.5Hz)**
Motor Speed	Decrease: $S_2 = (f_{min}/f_{nom})* S_1$, therefore $S_2 = (59.3/60)* S_1 = 0.988* S1$	Increase: $S_2 = (f_{max}/f_{nom})* S_1$, therefore $S_2 = (60.5/60)* S_1 = 1.008* S_1$
Motor Brake Horsepower (BHP)	Decrease: $BHP_2 = (f_{min}/f_{nom})^3 * BHP_1$, therefore $BHP_2 = (59.3/60)^3 * BHP_1 = 0.965 * BHP_1$	Increase: $BHP_2 = (f_{max}/f_{nom})^3 * BHP_1$, therefore $BHP_2 = (60.5/60)^3 * BHP_1 = 1.025 * BHP_1$
Pump Flow (Q)	Decrease: $Q_2 = (f_{min}/f_{nom})* Q_1$, therefore $Q_2 = 0.988 * Q_1$	Increase: $Q_2 = (f_{max}/f_{nom})* Q_1$, therefore $Q_2 = 1.008 * Q_1$
Pump NPSH available (NPSHa)	Increased margin by decreasing flow loss component of NPSH: $\Delta P_2 = (f_{min}/f_{nom})^2 * \Delta P_1 = (59.3/60)^2 * \Delta P_1 = 0.977 * \Delta P_1$	decreased margin by increasing flow loss component of NPSH: $\Delta P_2 = (f_{max}/f_{nom})^2 * \Delta P_1 = (60.5/60)^2 * \Delta P_1 = 1.017 * \Delta P_1$

Fan Flow (Q)	Decrease: $Q_2 = (f_{min}/f_{nom})* Q_1$, therefore $Q_2 = 0.988 * Q_1$	Increase: $Q_2 = (f_{max}/f_{nom})* Q_1$, therefore $Q_2 = 1.008 * Q_1$
Valve Opening Time (T_o)	Increased	Decreased
Valve Closing Time (T_c)	Increased	Decreased
DG Loading[3]	Decreased by $(f_{min}/f_{nom})^3$ or 0.965 if all loads assumed inductive.	Increased by $(f_{max}/f_{nom})^3$ or 1.025 if all loads assumed inductive

Table 3: Parameters Predictions as a Function of Frequency Variations

During DG operation in emergency mode all engine trip signals are over-ridden except for the following:

- Engine Overspeed (660 rpm)
- Engine low lube oil pressure (30 psig)
- Generator differential

Generator differential is not considered of concern in this evaluation since changes in DG frequency is expected to occur simultaneously with the changes in engine speed. The engine flywheel is directly coupled to the generator such that a nominal frequency of 60Hz corresponds to a rated engine speed of 600 rpm which is controlled by a governor. As the governor adjusts the fuel supply to the engine cylinders, engine speed is also adjusted.

Diesel Generator mechanical rotational speed, n, is directly proportional to its frequency, f, and inversely proportional to the number of magnetic poles, p as follows:

$$n = \frac{120.f}{p} \quad where\, p = 12 \qquad [1]$$

Therefore for f_{min} = 59.3Hz, n_{min} = 593 rpm (**decrease of 1.17%**) and f_{max} = 60.5Hz, n_{max} = 605 rpm **(increase of 0.83%).**

7.1 Diesel Generator Lube Oil and Jacket Water Systems

A. DG Lube Oil

The diesel engine contains its own lubricating oil system which provides oil at the proper flow, pressure, temperature, and cleanliness to lubricate and cool internal moving parts. The engine has three lube oil pumps. The normal source of lubricating oil while the engine is operating is the engine-driven pump which is a rotary gear, positive displacement pump. The standby motor-driven lube oil pump serves as a backup for the engine-driven lube oil pump, and starts upon a low lubricating oil pressure. There is also a motor-driven pre-lube pump which provides lube oil circulation whenever the engine speed is below 280 rpm while the diesel engine is starting, coasting down, or in a standby condition.

[3] This is a simplified estimation which does not account for voltage variations. See Table 4 for diesel loading estimation

The volumetric flow rate of the engine driven lube oil pump will decrease or increase proportionately to the decrease or increase in engine speed. As such, a DG operating at the minimum steady state frequency (59.3Hz) will reduce the volumetric flow rate of the lube oil pump by approximately 1.2%. The engine-driven pump has a flow rate capacity of 530 gpm (670 gpm for DG E) when DG is operating at 600 rpm[4]. A 1.2% decrease in this flow rate would result in flow reduction up to approximately 6.4 gpm (8.1 gpm for DG E). This is deemed negligible and of no adverse consequence since the discharge pressure of a positive displacement pump remains relatively constant and is independent of the shaft speed. The normal operating pressure of the DG engine driven lube oil pump of 50 psig is well above the engine low lube oil pressure setting of 30 psig. Therefore the small increase (+0.8%) or decrease (-1.2%) in DG speed when operating at minimum or maximum frequency respectively will not adversely impact the lube oil pump discharge pressure.

B. DG Jacket Water

The DG jacket water system maintains the engine warm in a state of readiness when in standby and removes during diesel operation the heat generated during the combustion process. The engine-driven jacket water pump is a single-stage centrifugal pump and its discharge pressure variation is proportional to the square of the change in speed. Under normal operation, the engine-driven jacket water pump pressure for DGs A through E is 30 psig [5] and its low pressure alarm is 12 psig and 10 psig for DGs A through D and E respectively. When the DG is operating at the minimum steady state frequency (59.3Hz), the engine-driven jacket water pressure will decrease by approximately 0.70 psig for all five DGs from its nominal value and calculated as follows:

$$\frac{P_2}{P_1} = \left(\frac{n_2}{n_1}\right)^2 \rightarrow P_2 = \left(\frac{1730}{1750}\right)^2 * (30\,psig) = 29.30\,psig \qquad [2]$$

The resulting minimum engine-driven jacket water pressure of approximately 29.30 psig is well above the jacket water low pressure alarm setpoint of 12 psig and 10 psig for DG A and E respectively. The DG overspeed trip setpoint is at 660 rpm (Reference 6.4.19 & 6.4.20) therefore, the diesel will continue running should its steady state frequency vary to the maximum allowable value of 60.5Hz (605 rpm). At the subject maximum frequency, the operating engine-driven jacket water pump pressure would be approximately 30.5 psig corresponding to an approximate increase of 0.5 psig from its normal operating value. Therefore, DG frequency variations within the specified range will not adversely impact the engine-driven jacket water pump capability to provide essential cooling to the engine during operation.

7.2 Diesel Generator Fuel Oil Storage and Transfer System

The diesel fuel oil system stores and delivers fuel oil for operation of the diesel engine. Four 50,000 gallon nominal capacity storage tanks are provided for DGs A through D and one 80,000 gallon nominal capacity storage tank is provided for DG E. One storage tank is provided for each DG with fuel oil stored in each tank sufficient for at least seven days of DG full load continuous operation. One DG fuel oil

[4] Reference 6.4.19 & 6.4.20
[5] Reference 6.4.10

transfer pump is provided for each storage tank and delivers fuel from the fuel oil storage tank to the fuel oil day tank. These pumps are horizontal, centrifugal type rated at 25 gpm at 30 psi differential head and 20 gpm at 50 ft. of water T.D.H for DGs A through D and DG E respectively (Reference 6.1.8). When accounting for corrections associated with tank internals, the usable volume of DGs A - D fuel oil tank is 47,438 gallons and the required fuel oil needed for seven days of operation at full load (i.e. 4000kW) is 45,864 gallons. On the other hand, the usable volume of fuel oil available in DG E storage tank is 73,253 gallons and the required fuel oil needed for seven days of operation at full load operation (i.e. 5000kW) is 56, 683 gallons. As such, DGs A - D and DG E fuel oil tanks have respectively approximately 1,574 gallons and 16,670 gallons of spare volume. The capacity of the transfer pump is greater than the fuel oil consumption rate of the diesel engine during operation and the pump can supply fuel oil to the DG and simultaneously increase the inventory of the day tank. When considering DG steady state operation at the minimum steady state voltage and frequency, the DG fuel oil transfer pump flow rate would decrease in the worst case by approximately 2.06% (~ 0.52 gpm at 30 psi). The resulting flow capacity of approximately 24.5 gpm for DGs A-D (19.6 gpm for DG E) still exceeds the DG fuel oil transfer pump flow rate requirement of 6.84 gpm and 5.86 gpm for DGs A- D and DG E respectively[6].

The aforementioned worst case change in pump flow rate due to voltage and frequency variations is approximated from the following formula (Reference 6.2.4) and conservatively assuming the resulting postulated steady state voltage (V_2) at 90 percent of equipment rating per section 4.7:

$$\Delta S = \left[\left(\frac{V_1 . f_2}{V_2 . f_1}\right)^2 - 1\right] . (S_{Sync} - S_1) + S_1 . \left(1 - \frac{f_2}{f_1}\right) \qquad [3]$$

Where

V_1 = 460V; V_2 = 414V; f_1 = 60Hz; $f_2 = f_{min}$ = 59.3Hz; S_{sync} = 3600 rpm (1800 rpm for DG E) and S_1 = 3450 rpm (1745 rpm for DG E) (Reference 6.4.22 & 6.4.29)

ΔS = 71.14 rpm (31.68 rpm for DG E) and ($\Delta S/S_1$) = 2.06% (1.82% for DG E)

Conversely DG operation at a maximum steady state voltage and frequency will increase fuel oil transfer pump flow rate by approximately 1.53% and 1.34% for DG A and E respectively. This increase in DG fuel oil transfer pump flow rate will result in increased pipe velocities and system pressures. The flow velocity for the fuel oil transfer and tie lines and the day tank overflow line under maximum steady state voltage and frequency could be estimated as follows:

$$V_2 = \left(\frac{n_2}{n_1}\right) . V_1 \rightarrow V_2 \cong \left(\frac{3503}{3450}\right) . V_1 \cong 1.0153 . V_1 \text{ (1.0134.}V_1\text{ for DG E)} \qquad [4]$$

Here V_1 is the velocity for the fuel oil transfer discharge lines velocity at nominal frequency.
The increase in fuel oil transfer pump speed when the DG is operating at maximum steady state voltage and frequency is also expected to increase operating pressure by approximately 3.1% calculated as follows:

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[6] See Section 3.6

$$\frac{P_2}{P_1} = \left(\frac{n_2}{n_1}\right)^2 \rightarrow P_2 = \left(\frac{3503}{3450}\right)^2 . P_1 = 1.031. P_1 \quad (1.0269.P_1 \text{ for DG E}) \qquad [5]$$

Applying the above pressure adjustment to DG A and E engine driven fuel oil pump pressure of 35 psi[7] results in 36.1 psig which remains below the system design pressure of 60 psig[8] with sufficient margin to yield no adverse impact.

The increased fuel oil flow in turn increases suction side losses and reduces available NPSH (NPSHa) while the decreased speed will result in decrease flow which in turn decreases suction side losses and increases NPSHa. As such, based on the aforementioned relationship, the margin between NPSHa and the required NPSH (NPSHr) would increase by approximately 4.1% (3.6% for DG E) during DG steady state operation at 59.3Hz as compared to its operation at nominal frequency (60Hz). Conversely NPSH margin (i.e. NPSHa – NPSHr) would decrease by approximately 3.1% (2.69% for DG E) when the diesel is operating at a steady state frequency of 60.5Hz. At the lowest fuel level at the center line of the pump, the NPSHa is approximately 39' and the NPSHr is 4.5' according to the pump test curves[9]. Therefore, more than 33' NPSH margin would remain when accounting for the 3.1% decrease in the NPSHa. The excess margin in NPSHa is more than sufficient to compensate for the changes in pump flow rate resulting from the consideration of DG frequency and voltage variations.

7.3 Diesel Loading

The standby diesel generators supply a highly reliable, self-contained source of power to aligned 4.16kV ESF busses in the event of a complete loss of offsite power (LOOP). These DGs are designed to provide sufficient power for the electrical loads required for a simultaneous shutdown of both reactors including a LOCA /LOOP on one unit concurrent with a safe shutdown of the other unit.

A total of five DGs are shared by the two units with DGs A through D, identical in construction and equipment, normally aligned to the safety related load groups and DG E substitutable for any of the DGs A – D without violating the independence of the redundant safety related load groups.

Diesel Generators A - D are rated 4000kW for continuous operation and 4700kW for 2000 hour (greater than 83 days) while the fifth diesel, DG E, has a continuous rating of 5000kW and 2000 hour rating of 5500kW. When assuming for simplicity that all loads fed from the diesel are affected by frequency changes only, Table 3 shows that DG load would decrease by approximately 3.5% during operation at 59.3Hz and would increase by approximately 2.5% during operation at 60.5Hz from its equivalent loading at nominal frequency.

The cumulative impact of the voltage and frequency variations on DG loading was evaluated for its worst case loading scenario (Unit 1 LOCA/LOOP and Unit 2 forced shutdown when DG B is unavailable). Given the similarities in construction and equipment between DGs A – D, the loading analysis was limited to DGs A and E. Under the considered worst case DBA scenario, DG A is the most loaded 60 minutes and beyond the inception of the event. Therefore, the results of voltage and frequency

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[7] Reference 6.4.19 & 6.4.20

[8] Reference 6.4.27 & 6.4.28

[9] Reference 6.1.8

variations on DG A and DG E, when substituted for DG A, are considered bounding for all five diesels. Table 4 below summarizes DGs A and E total loadings calculated per Equation [3] applied to Table 1. See Exhibit 9 for details of the methodology used to derive Table 4 as well as other related computations.

		V_{Rated}			V_{Min1}			V_{Nom}			V_{Max}		
		kW	kVAR	kVA	kW	kVAR	kVA	kW	kVAR	kVA	kW	kVAR	kVA
f_{Rated}	$Total_{Calc}$ DG A	3922.85	1765.40	4301.79	3873.68	1757.42	4253.69	3960.47	1770.78	4338.32	4016.72	1777.80	4392.57
	$Total_{Calc}$ DG E	4161.35	1830.78	4546.27	4101.12	1822.50	4487.84	4207.84	1836.37	4591.09	4277.93	1843.65	4658.29
f_{Min}	$Total_{Calc}$ DG A	3801.75	1705.94	4166.95	3753.31	1698.32	4119.66	3838.87	1711.43	4203.09	3894.48	1717.78	4256.50
	$Total_{Calc}$ DG E	4035.70	1769.12	4406.44	3976.23	1761.22	4348.83	4081.68	1774.87	4450.87	4151.10	1781.41	4517.20
f_{Max}	$Total_{Calc}$ DG A	4011.03	1808.69	4399.97	3961.32	1800.44	4351.28	4049.01	1814.25	4436.89	4105.74	1821.50	4491.66
	$Total_{Calc}$ DG E	4252.84	1875.67	4648.10	4192.05	1867.12	4589.06	4299.70	1881.45	4693.32	4370.28	1888.97	4761.05

V_{min1} = 3793V; V_{rated} = 4000V; V_{nom} = 4160V; V_{max} = 4400V; f_{min} = 59.3Hz; f_{rated} = 60Hz; and f_{max} = 60.5Hz

Table 4: Diesel Generators A and E Total Estimated Loading when Unit 1 LOCA/LOOP & Unit 2 Forced Shutdown with DG B Unavailable (at 60 Min & Beyond)- All ESF and Non-ESF Loads Considered.

It is to be noted that the FSAR diesel loading table considered (i.e. FSAR Table 8.3-3) shows two RHR Service Water (RHRSW) pumps in operation, one for the unit with a DBA (DG C load) and one for the forced shutdown unit (DG A load). Per SSES design, only one loop RHRSW with one pump running is required to remove decay heat for both units. As such, more than 460kW not required for design basis accident mitigation are accounted for in the above DG loading table. Additionally, FSAR loading tables 8.3-2 through 8.3-5 account for both ESF and selected non-ESF loads to diesel generators and ESS buses. The non-ESF loads are not required for mitigating the effects of a design basis event of LOCA/LOOP on one unit and forced shutdown of the second unit and their ultimate operation status is at plant operations discretion. The subject Non-ESF loads account for more than 620kW of DG A loading beyond one hour of operation under the considered DBA scenario (See Exhibit 7). Table 4 above shows that when considering all ESF and Non-ESF Loads with the aforementioned loading conservatisms, DG A total loading at 60 minutes beyond the DBA evaluated could slightly exceed (~ 2.65% max) its continuous rating of 4000kW for 4 cases as highlighted in the subject table. Consequently, DGs A and E loading when considering voltage and frequency variations is further evaluated by refining the loads to remove Non-ESF loads that are manually initiated (Reference 6.1.9) during the design basis event under consideration. This is acceptable not only because these are Non-ESF loads not required to mitigate the worst case DBA, but they are also manually initiated. Table 5 below was used to revise loading information when Non-ESF loads manually initiated are not considered. Of noteworthiness is the fact that RHRSW loading (~460kW or ~ 11.5% of DG A continuous loading) was maintained for additional margin.

		Diesel Generator A			
		Demand kW			
Equipment No.	Loads	Number Connected	0-10 Min.	10-60 Min.	60 Min & Beyond
UNIT 1 DBA LOADS					
1V210 A,B,C,D	RHR Pump Room Unit Coolers	1	9	9	9
1V506 A,B	RHR Service Water Pump House Supply Fans (RHRSWP)	1	-	4.6	4.6
Unit 2 Forced Shutdown Load					
2P506 A,B**	RHR Service Water Pumps	1	-	463	463
TOTAL ESF LOADS MANUALLY INITIATED			9	**476.6**	**476.6**
Non-ESF Loads					
2P132A	CRD Water Pumps. Unit 2 Essential Lighting	1	-	215	163
		Set	96	96	96
1P/2P109 – A-H,J 1S/2S103,104	Turbine Generator Bearing Lift Pump & Turning Gear	1	-	119	119
1K/2k107 A,B	Instrument Air Compressor	1	-	82	82
1S/2S106 A,B,C	RFPT Turning Gear	3	-	4.8	4.8
TOTAL Non- ESF LOADS MANUALLY INITIATED			96	**516.8**	**464.8**
			--------	--------	-------
TOTAL COMBINED MANUALLY INITIATED LOADS			105	**993.4**	**941.4**

Table 5: DG A ESF and Non-ESF Manually Initiated Loads per FSAR Table 8.3-1

	DG A Demand kW					
	0 - 10 Minutes		**10 - 60 Minutes**		**60 Minutes & Beyond**	
	kW-Constant Z	**kW-Constant VA**	**kW-Constant Z**	**kW-Constant VA**	**kW-Constant Z**	**kW-Constant VA**
Unit 1 ESF Loads Lumped (DBA)	111.0	38.5	111.0	43.1	111.0	118.1
Unit 2 ESF Loads Lumped (FSD)	75.0	75.5	75.0	75.5	75.0	75.5
Unit 1 & 2 Common Loads Lumped	28.6	123.5	19.6	105.5	19.6	105.5
	--------	--------	--------	--------	--------	--------
Total Lumped ESF Loads	214.6	237.5	205.6	224.1	205.6	299.1
Non-ESF Loads Manually Initiated	96	0	96	420.80	96	368.80
Other Non-ESF Loads	29	121	26	126.40	26	126.40
	--------	--------	--------	--------	--------	--------
Total Non-ESF Loads	124.8	121.4	122.0	547.2	122.0	495.2
Total ESF & Other Non-ESF Loads	**243.4**	**358.9**	**231.6**	**350.5**	**231.6**	**425.5**
Total All Lumped Loads	339.4	358.9	327.6	771.3	327.6	794.3

Table 6: DG A Lumped Loads per Category

NOTE:

- Load 1PP100 partially manually initiated (5kW at 10 min from DBA) is conservatively not included.
- Total ESF & Other Non-ESF Loads is calculated as Total Lumped ESF Loads + Other Non-ESF Loads. These values represent the total loads to be lumped when manually initiated Non-ESF loads are not accounted for.

The results for Table 5 and Table 6 are then used to generate Table 7 which is subsequently used per the methodology and steps described in Exhibit 9 to estimate DGs total loading as summarized in Table 8

	Motor Loads			Static Load	
	BHP	kW	kVAR	kW	kVAR
CS	691	552	268.1	[redacted]	[redacted]
RHR	1798	1429	659.6	[redacted]	[redacted]
RHRSW	574	463	256.9	[redacted]	[redacted]
ESW	440	357	196.1	[redacted]	[redacted]
U1 Lump*	-	350	169.5	156.55	[redacted]
U2 ESF Loads Lumped (FSD)	-	75.5	36.6	75.0	[redacted]
DGE Lump	-	135	65.4	103.5	[redacted]

* U1 Lump = (Total ESF & Other Non-ESF Loads) - Unit 2 ESF Loads Lumped (FSD)

Table 7: DGs A and E Loading per FSAR Tables 8.3-3 & 8.3-3a When Manually Initiated Non-ESF Loads Not Considered.

		V_{Rated}			V_{Min1}			V_{Nom}			V_{Max}		
		kW	kVAR	kVA	kW	kVAR	kVA	kW	kVAR	kVA	kW	kVAR	kVA
f_{Rated}	$Total_{Calc}$ DG A	3458.05	1586.78	3804.73	3420.26	1579.62	3767.41	3486.69	1591.61	3832.78	3529.12	1597.90	3874.01
	$Total_{Calc}$ DG E	3696.55	1652.16	4048.97	3647.70	1644.70	4001.35	3734.05	1657.19	4085.27	3790.32	1663.75	4139.40
f_{Min}	$Total_{Calc}$ DG A	3349.36	1533.34	3683.66	3312.22	1526.50	3647.06	3377.56	1537.95	3711.22	3419.41	1543.95	3751.82
	$Total_{Calc}$ DG E	3583.32	1596.52	3922.88	3535.15	1589.40	3876.01	3620.36	1601.32	3958.69	3676.03	1607.58	4012.17
f_{Max}	$Total_{Calc}$ DG A	3537.19	1625.69	3892.89	3498.92	1618.30	3855.04	3566.15	1630.68	3921.30	3609.01	1637.18	3962.99
	$Total_{Calc}$ DG E	3779.00	1692.68	4140.77	3729.65	1684.97	4092.61	3816.84	1697.88	4177.45	3873.55	1704.65	4232.05

Table 8; DG A and E Total Estimated Loading when Unit 1 DBA & Unit 2 Forced Shutdown with DG Unavailable (at 60 Min & Beyond) – Without Non-ESF Loads Manually Initiated

Thus, without the Non-ESF loads manually initiated[10], Table 8 shows that for the most severe design basis event, DGs A and E total loadings under limiting voltage and frequency variations within acceptable steady state ranges are within their respective continuous rating of 4000kW and 5000kW with at least approximately 9.8% and 22.5% additional margins for DGs A and E respectively.

A qualitative assessment of the diesel generator loading during all three time intervals (i.e. 0-10 Min; 10-60 Min; 60 Min & Beyond) when considering only frequency variations was additionally performed for ESF loads only and simplistically considering all ESF loads being affected by DG frequency variations. Table 9 and Table 10 results show for all the time intervals that DGs A, C, D and E total ESF loads for Unit 1 LOCA/LOOP and Unit 2 Forced Shutdown with DG B unavailable remain within their continuous ratings with adequate margin remaining (~15.5% for DG A and 27.5% for DG E additional to the RHRSW load margin) to accept Non-ESF loads and account for concurrent voltage variations. Therefore, the DG total loading required for mitigation of the worst case DBA evaluated will remain below its continuous rating even with consideration of its operation at various steady state voltage and frequency within the acceptable Tech Spec ranges evaluated herein.

[10] See Table 5 for the specific loads.

DIESEL GENERATOR TOTAL ESF LOADING WITH DG B UNAVAILABLE; UNIT 1 DBA AND UNIT 2 FORCED SHUTDOWN										
DESCRIPTION		0 - 10 Minutes			10 - 60 Minutes			60 Minutes & Beyond		
		DG A	DG C	DG D	DG A	DG C	DG D	DG A	DG C	DG D
Unit 1 Total DBA Loads	Rated Freq	2142.3	2122.5	2062.1	2146.9	1147.5	70.1	2221.9	1234.5	70.1
	Min Freq	2068.1	2049.1	1990.8	2072.6	1107.8	67.7	2145.0	1191.8	67.7
	Max Freq	2196.3	2176.0	2114.1	2201.0	1176.4	71.9	2277.9	1265.6	71.9
Unit 2 Total Forced Shutdown Loads	Rated Freq	150.5	149.6	115.2	613.5	149.6	1553.2	613.5	149.6	1553.2
	Min Freq	145.3	144.4	111.2	592.3	144.4	1499.5	592.3	144.4	1499.5
	Max Freq	154.3	153.4	118.1	629.0	153.4	1592.4	629.0	153.4	1592.4
Unit 1 & Unit 2 Total Common Loads	Rated Freq	497.3	1206.4	600.5	470.3	1179.4	573.5	470.3	1179.4	573.5
	Min Freq	480.1	1164.7	579.7	454.0	1138.6	553.7	454.0	1138.6	553.7
	Max Freq	509.8	1236.8	615.6	482.2	1209.1	588.0	482.2	1209.1	588.0
		------	------	------	------	------	------	------	------	------
Total ESF Loads	**Rated Freq**	**2790.1**	**3478.5**	**2777.8**	**3230.7**	**2476.5**	**2196.8**	**3305.7**	**2563.5**	**2196.8**
	Min Freq	**2693.5**	**3358.1**	**2681.7**	**3118.9**	**2390.8**	**2120.8**	**3191.3**	**2474.8**	**2120.8**
	Max Freq	**2860.4**	**3566.2**	**2847.9**	**3312.1**	**2538.9**	**2252.2**	**3389.0**	**2628.1**	**2252.2**

Table 9: Diesel Generator A, C & D Total ESF Loading for Unit 1 LOCA/LOOP & Unit 2 Force Shutdown and DG B Unavailable

DIESEL GENERATOR E TOTAL ESF LOADING WITH DG B UNAVAILABLE; UNIT 1 DBA AND UNIT 2 FORCED SHUTDOWN										
DESCRIPTION		0 - 10 Minutes DG E Substituted for:			10 - 60 Minutes DG E Substituted for:			60 Minutes & Beyond DG E Substituted for:		
		DG A	DG C	DG D	DG A	DG C	DG D	DG A	DG C	DG D
Unit 1 Total DBA Loads	Rated Freq	2344.79	2324.98	2260.16	2376.39	1376.98	295.16	2451.39	1463.98	295.16
	Min Freq	2263.68	2244.55	2181.97	2294.18	1329.35	284.95	2366.59	1413.34	284.95
	Max Freq	2403.90	2383.59	2317.14	2436.30	1411.69	302.60	2513.19	1500.89	302.60
Unit 2 Total Forced Shutdown Loads	Rated Freq	150.5	149.6	115.2	613.5	149.6	1553.2	613.5	149.6	1553.2
	Min Freq	145.29	144.42	111.21	592.28	144.42	1499.47	592.28	144.42	1499.47
	Max Freq	154.29	153.37	118.10	628.97	153.37	1592.35	628.97	153.37	1592.35
Unit 1 & Unit 2 Total Common Loads	Rated Freq	497.30	1206.40	600.50	470.30	1179.40	573.50	470.30	1179.40	573.50
	Min Freq	480.10	1164.67	579.73	454.03	1138.60	553.66	454.03	1138.60	553.66
	Max Freq	509.84	1236.81	615.64	482.16	1209.13	587.96	482.16	1209.13	587.96
Total ESF Loads	**Rated Freq**	**2992.59**	**3680.98**	**2975.86**	**3460.19**	**2705.98**	**2421.86**	**3535.19**	**2792.98**	**2421.86**
	Min Freq	**2889.07**	**3553.64**	**2872.92**	**3340.49**	**2612.37**	**2338.08**	**3412.90**	**2696.36**	**2338.08**
	Max Freq	**3068.03**	**3773.77**	**3050.88**	**3547.42**	**2774.19**	**2482.91**	**3624.31**	**2863.39**	**2482.91**

Table 10: Diesel Generator E Total ESF Loading for Unit 1 LOCA/LOOP & Unit 2 Force Shutdown and DG B Unavailable

7.4 Diesel Fuel Oil Consumption

Diesel Generator required fuel oil volumes for seven days of operation are determined based on DG full load continuous rating of 4000 kW for DGs A-D and 5000kW for DG E. As discussed in Section 7.3, the total loading of each DG required for mitigation of Unit 1 DBA with Unit 2 Forced Shutdown while operating within the acceptable Tech Specs steady state voltage and frequency ranges remain below

their continuous ratings. Additionally, per Section 7.2, DGs A - D and DG E fuel oil tanks have respectively approximately 1,574 gallons and 16,670 gallons of spare volume above the volume required for their seven days of continuous operation. Therefore, DG fuel oil consumption resulting from its operation within the steady state voltage and frequency ranges considered will not adversely impact the fuel oil volume required for seven days of continuous operation of each diesel. As such, there is no impact to the existing calculated DG fuel oil consumption rate.

7.5 Effects on Motors

Per section 4.7, safety related motors are designed to perform their safety functions with a steady state voltage ± 10% of the equipment rating. The torque developed by a motor is proportional to the square of its terminal voltage and inversely proportional to the square of its power supply frequency. As such, the following adjustments are made to the baseline motor torque values:

$$T_2 = T_1 . \left(\frac{V_2}{V_1}\right)^2 \qquad [6]$$

Where:

T_1 = torque at voltage V_1 (ft-lb)
T_2 = torque at voltage V_2 (ft-lb)
V_1 = baseline voltage (V)
V_2 = postulated voltage (V)

$$T_2 = T_1 . \left(\frac{f_1}{f_2}\right)^2 \qquad [7]$$

Where:

T_1 = torque at frequency f_1 (ft-lb)
T_2 = torque at frequency f_2 (ft-lb)
f_1 = baseline frequency (60Hz)
f_2 = postulated frequency (Hz)

The synchronous speed of a motor is proportional to the power supply frequency and the net effect of voltage and frequency variations on motor steady-state speed is approximated as the sum of the changes due to voltage and frequency respectively. The following expression was used to estimate this effect:[11]

$$\Delta S = \left(\left(\frac{V_1 . f_2}{V_2 . f_1}\right)^2 - 1\right) . \left(S_{synch} - S_1\right) + S_1 . \left(1 - \frac{f_2}{f_1}\right) \qquad [8]$$

and the resulting speed $S_2 = S_1 - \Delta S$ [9]

[11] See reference 6.2.4 for derivation details.

Where:

f_1 = baseline frequency (60Hz);
f_2 = postulated frequency (Hz);
V_1 = baseline voltage (V);
S_1 = rated speed at V1 and f1 (rpm)
ΔS = Change in speed (rpm)
V_2 = postulated voltage (V)

For the major motor loads evaluated individually, Table 11 below provides the results of calculated changes in motor speed and horsepower due to changes in DG steady state voltage and frequency.

	Frequency (Hz)			Voltage (V)				Rated Speed		
Loads	fRated	fMin	fMax	VRated	VMin1	VNom	VMax	S1 (rpm)	Ssynch	# Poles
Reactor Core Spray Pumps	60	59.3	60.5	4000	3793	4160	4400	1780	1800	4
RHR Pumps	60	59.3	60.5	4000	3793	4160	4400	1185	1200	6
RHR Service Water Pumps	60	59.3	60.5	4000	3793	4160	4400	1180	1200	6
Emergency Service Water Pumps	60	59.3	60.5	4000	3793	4160	4400	1775	1800	4

		ΔS (rpm)				Resulting Speed $S_2 = S_1 - \Delta S$ (rpm)				(S2/S1) = 1- (ΔS/S1)				HP2 = (f2/f1)^3*HP1 (Affinity Laws)			
		VRated	VMin1	VNom	VMax	VRated	VMin1	VNom	VMax	VRated	VMin1	VNom	VMax	VRated	VMin1	VNom	VMax
Freq (Hz)	fRated	0	2.24	-1.509	-3.47	1780	1778	1782	1783	100.0%	99.874%	100.08%	100.20%	100.0%	99.62%	100.25%	100.59%
		0	1.68	-1.132	-2.60	1185	1183	1186	1188	100.0%	99.858%	100.10%	100.22%	100.00%	99.57%	100.29%	100.66%
		0	2.24	-1.509	-3.47	1180	1178	1182	1183	100.0%	99.810%	100.13%	100.29%	100.00%	99.43%	100.38%	100.89%
		0	2.80	-1.886	-4.34	1775	1772	1777	1779	100.0%	99.842%	100.11%	100.24%	100.00%	99.53%	100.32%	100.74%
	Average													100.00%	99.54%	100.31%	100.72%
	fMin	20.30	22.49	18.83	16.91	1760	1758	1761	1763	98.859%	98.736%	98.942%	99.050%	96.62%	96.26%	96.86%	97.18%
		13.48	15.12	12.37	10.93	1172	1170	1173	1174	98.863%	98.724%	98.956%	99.077%	96.63%	96.22%	96.90%	97.26%
		13.30	15.49	11.83	9.91	1167	1165	1168	1170	98.873%	98.687%	98.998%	99.160%	96.66%	96.11%	97.02%	97.50%
		20.13	22.87	18.29	15.89	1755	1752	1757	1759	98.866%	98.712%	98.970%	99.105%	96.64%	96.18%	96.94%	97.34%
	Average													96.63%	96.19%	96.93%	97.32%
	fMax	-14.50	-12.22	-16.03	-18.03	1794	1792	1796	1798	100.81%	100.69%	100.90%	101.01%	102.46%	102.07%	102.73%	103.07%
		-9.62	-7.91	-10.77	-12.27	1195	1193	1196	1197	100.81%	100.67%	100.91%	101.04%	102.46%	102.02%	102.75%	103.14%
		-9.50	-7.22	-11.03	-13.03	1189	1187	1191	1193	100.80%	100.61%	100.93%	101.10%	102.43%	101.85%	102.83%	103.35%
		-14.37	-11.52	-16.29	-18.78	1789	1787	1791	1794	100.81%	100.65%	100.92%	101.06%	102.45%	101.96%	102.78%	103.21%
	Average													102.45%	101.97%	102.77%	103.19%

Table 11: Speed & HP Variation Matrix of Major Motor Loads

The maximum change in motor horsepower (HP2), estimated using the Affinity Laws, will occur when the DG is operating at maximum steady state voltage and frequency (i.e. 4400V and 60.5Hz).

The effect of frequency variations on induction motor operating temperature is also evaluated based on the proportional relationship between the motor operating temperature and the square of the horsepower to rated horsepower ratio.

$$\Delta T_{insul} = \left[\left(\frac{HP}{HP_{S.F}}\right)^2 - 1\right] . T_{rise@S.F} \quad [12] \qquad [10]$$

Where:

ΔT_{insul} is the change in motor temperature rise

[12] Reference 6.2.9

HP = motor horsepower;

$HP_{S.F}$ = motor horsepower at service factor;

$T_{rise@SF}$ = temperature rise of the insulation at service factor

Based on parameter relationships established in Table 3 and Equation [10], changes in motor rise temperature due to DG operation at steady state operation at steady state frequencies other than nominal is calculated as follows:

$$For\ DG\ operating\ frequency\ at\ 59.3Hz, \Delta T_{insul} = \left[\left(\frac{0.965.HP_{SF}}{HP_{SF}}\right)^2 - 1\right].T_{rise@SF} \cong -6.9\%$$

$$and\ for\ operating\ frequency\ at\ 60.5Hz, \Delta T_{insul} = \left[\left(\frac{1.025.HP_{SF}}{HP_{SF}}\right)^2 - 1\right].T_{rise@SF} \cong 5.1\%$$

Typical AC induction motor windings (Non-EQ motors) installed in the plant have Class B or F insulation system with a 40°C ambient temperature. Per Reference 6.2.5 (Section 12.42 and 12.43), the lowest motor winding temperature rises, based on a maximum ambient temperature of 40°C, for Class B and F insulation systems are 80°C and 105°C respectively. Therefore a 5.1% increase or 6.9% decrease in motor insulation temperature rise, above the temperature of the cooling medium, would not yield abnormal deterioration of the motor insulation system during the worst case DBA considered or have significant effect on motor life.

Continuously operated EQ motors have a qualified life of 40 years at an operating temperature of 175°C, including a winding temperature rise of approximately 110°C. The actual motor winding temperature based on normal operating load conditions and worst-case nominal normal plant voltage is 75 °C[13]. Therefore, even when considering the effect of DG steady state frequency variations on motor operating temperature, the 40-year qualified life of EQ motors at 175 °C still envelops the plant equipment's maximum service temperature with more than sufficient margin in the windings.

7.6 MOV Performance

DG voltage and frequency variations within allowable Tech Spec steady state limits would have an impact on motor-operated valves (MOVs) similar to the impact on other induction motors such as pump motors as evaluated in Section 7.5. Steady state frequency higher than nominal value would increase the speed of the MOV motor while lower steady state frequency would reduce the motor speed.

The MOVs are fed by the 480V system and the motor torque capability is calculated based on the ESS 4kV bus voltage set at the minimum degraded grid voltage dropout of 91.2% (~ 3793V). This setting represents the most degraded voltage level expected when accounting for the degraded voltage relay (DVR) tolerance prior to the bus undervoltage protection (DVR) scheme operation[14]. The lower end of the DG allowable steady state Tech Spec voltage of 4000V is higher by approximately 207V than the 4kV ESS bus voltage level currently used to evaluate MOV motor torque capability. Therefore, the current

[13] Reference 6.4.15

[14] Reference 6.4.5

calculation method for MOV motor torque capability bounds the DG minimum Tech Spec allowable steady state voltage of 4000V.

DG operation at steady state frequency of 59.3Hz will increase the MOV close stroke time while its operation at 60.5Hz will slightly shorten the subject close stroke time. A slightly shorter close stroke time, due to an increase in motor speed operating at higher than nominal frequency, will not adversely impact the valve performance. A total of 74 MOVs are identified as critical and having a Tech Spec or FSAR stroke time limits. The stroke time of these valves when adjusted for the effects of DG steady state frequency variations have positive margin remaining when compared with the Limiting Value for Full Stroke Time (Reference 6.4.5). Therefore, even when considering the effects of DG operation at steady state voltage and frequency within their Tech Spec allowable ranges, their impact on MOV operation is negligible with no adverse impact to the Limiting Value for Full Stroke Time

7.7 Effects on RHR and Core Spray Injection Flow Under Accident Conditions

The effects of DG voltage and frequency variations were evaluated per Reference 6.4.21 for the lowest margin flow systems credited in the safety analysis, namely RHR, Core Spray and RHRSW. For all three systems, flow rates used in the LOCA analysis remain conservative even when considering DG operation at minimum voltage and frequency. Therefore, the capability of these safety related systems to perform their intended safety functions is not adversely affected by DG operation within the allowable Tech Spec voltage and frequency ranges. See Reference 6.4.21 for evaluation methodology and other details.

7.8 Battery Chargers

As part of the long-term mitigation of Unit 1 DBA and Unit 2 Forced Shutdown, the following safety related battery chargers are supplied by the DGs:

- 250V DC ESS Battery Chargers
- 125V DC Battery Chargers

Per battery charger vendor manuals (References 6.4.17 and 6.4.18), the charger will regulate output voltage within ± 0.5% of the desired steady state voltage with ± 10% variations of the AC line voltage and AC frequency variations of ± 5% (i.e. ± 3Hz). The DG steady state voltage and frequency variation ranges considered in this analysis remain within the aforementioned ranges. Therefore, the output from the battery chargers would vary by less than 0.5% which is considered negligible with no adverse impact.

7.9 DGs A and E ETAP Transient Stability Modeling

ETAP 12.0.0N is used to perform transient stability studies for emergency diesel generators A and E as well as the four major induction motor loads started and accelerated during a Unit 1 DBA and Unit 2

Forced shutdown scenario (i.e. RHR, Core Spray, ESW and RHRSW). The transient stability analyses performed herein are limited to DGs A and E because DGs A through D have the same electrical and mechanical characteristics, and experience approximately similar transients during the postulated scenario. Per FSAR Table 8.3-3, DG A has the highest total load (60 minutes and beyond) under the worst case DBA scenario being evaluated. As such, the dynamic transient response obtained for DG A under this analysis envelops the transient response of DGs B, C, and D when subject to identical DBA loading scenarios. DG E is the fifth diesel which can be substituted for any of the other four diesels. It is a bigger engine (i.e. 5000kW) and its dynamic response, under the aforementioned worst case DBA scenario, when substituted to DG A would envelop its transient response when substituted for any of the other three diesels (B, C or D).

A computer model of DGs A and E and their essential loads was developed based on previous model per reference 6.4.7. Past DG surveillance test results, Unit 1 2010 LOCA/LOOP surveillance for DG A and Unit 2 2011 LOCA/LOOP surveillance, were used as a basis for tuning the diesels. Governor tuning parameters were adjusted in the model to mimic DG output parameters with actual digitized test data. Selection of the best achievable tuning model was dictated by the correlation of DG's speed/frequency, terminal voltage, and current profiles with actual digitized test results.

Separate induction motor models were used to simulate the transient performance of each of the four major 4kV motors (RHR, Core Spray, ESW and RHRSW). The input parameters for RHR, and Core Spray motors and their respective load models were implemented as user-defined (UDM) per data in Reference 6.4.7. Input data for ESW and RHRSW were determined per Reference 6.4.6 and Exhibit 10 respectively. These motors were then individually modeled dynamically and the changes in electrical characteristics due to DG voltage and frequency variations accounted for in the modeling per Table 11. Other DG loads per FSAR Tables 8.3-3 and 8.3-3a are modeled as Non-shed loads and lumped loads represented as a combination of constant kVA and constant impedance. Cables are also added to the model whenever deemed practical to closely represent field conditions and account for their contribution in the system dynamic response. Refer to Exhibit 6 for ETAP study case details.

ETAP Transient Stability module allows for the DG model to be immediately started in steady state isochronous mode including the steady state values of Non-shed loads. In order to compress the simulation time, time intervals between loading steps were reduced while still allowing for completion of each load transient and DG returning to steady state conditions. To simplify the DG's loading sequence, Non-shed and lumped loads are conservatively modeled to be ON upon closure of the DG breaker and prior to the start and acceleration of the major 4kV motors modeled individually. This simplification is acceptable when considering the size of individual loads lumped and the fact that the resulting dynamic response of the DGs upon sequencing of the large motor loads would be enveloping since the DGs would be preloaded at a higher value for each motor start and acceleration.

The DG frequency was adjusted through "Project → Standards → Frequency" and voltage was adjusted through the DG's Generation Category. This method of varying frequency has no impact on DG loading since it just introduces a new base frequency to the project and assumes that all model inputs are based on this frequency. Hence, manual adjustments of loading values for frequency variations per Exhibit 6

are appropriate. The manually adjusted percent load for dynamically modeled motors are entered into the "% Loading" tab for each model per Exhibit 6, and are then accessed from the study case editor. The kW and kvar inputs for constant kVA lumped loads are adjusted for each case per the methodology described in Exhibit 9. The static loads do not need manual adjustments from case to case.

The DGs real, reactive and apparent power steady state results of the DGs generated by the ETAP Transient Stability analyses compare well with the DGs total loading calculated per the qualitative approach described in Section 7.3. The variance between these results for all combination of DG voltage and frequency variations, per Table 12 and Table 13 below, is deemed negligible when considering various simplifications and conservatisms built into the qualitative approach. As such, the steady state results are considered similar and the DG dynamic response obtained from ETAP Transient Stability analysis is representative of the DG transient response when operating at the considered voltages and frequencies under a Unit 1 DBA and Unit 2 Force Shutdown scenario.

		V_{Rated}			V_{Min1}			V_{Nom}			V_{Max}		
		kW	kVAR	kVA	kW	kVAR	kVA	kW	kVAR	kVA	kW	kVAR	kVA
f_{Rated}	Total$_{ETAP}$ DG A	3880.10	1845.80	4296.76	3838.40	1824.10	4249.78	3905.50	1875.40	4332.44	3965.50	1943.30	4416.06
	Total$_{Calc}$ DG A	3922.85	1765.40	4301.79	3873.68	1757.42	4253.69	3960.47	1770.78	4338.32	4016.72	1777.80	4392.57
	Total$_{ETAP}$ DG E	4177.80	1983.10	4624.58	4140.90	1969.70	4585.50	4216.70	2012.30	4672.25	4154.00	2011.30	4615.31
	Total$_{Calc}$ DG E	4161.35	1830.78	4546.27	4101.12	1822.50	4487.84	4207.84	1836.37	4591.09	4277.93	1843.65	4658.29
f_{Min}	Total$_{ETAP}$ DG A	3764.00	1794.00	4169.67	3721.60	1767.20	4119.87	3800.30	1831.30	4218.52	3838.40	1896.20	4281.23
	Total$_{Calc}$ DG A	3801.75	1705.94	4166.95	3753.31	1698.32	4119.66	3838.87	1711.43	4203.09	3894.48	1717.78	4256.50
	Total$_{ETAP}$ DG E	3989.40	1900.20	4418.83	3945.10	1874.70	4367.87	4022.40	1932.80	4462.67	4069.30	1987.20	4528.59
	Total$_{Calc}$ DG E	4035.70	1769.12	4406.44	3976.23	1761.22	4348.83	4081.68	1774.87	4450.87	4151.10	1781.41	4517.20
f_{Max}	Total$_{ETAP}$ DG A	3963.50	1883.90	4388.44	3932.40	1868.80	4353.87	4003.30	1917.00	4438.61	4044.80	1975.00	4501.23
	Total$_{Calc}$ DG A	4011.03	1808.69	4399.97	3961.32	1800.44	4351.28	4049.01	1814.25	4436.89	4105.74	1821.50	4491.66
	Total$_{ETAP}$ DG E	4207.90	2001.50	4659.66	4165.70	1985.50	4614.68	4240.10	2028.10	4700.17	4282.40	2073.40	4757.93
	Total$_{Calc}$ DG E	4252.84	1875.67	4648.10	4192.05	1867.12	4589.06	4299.70	1881.45	4693.32	4370.28	1888.97	4761.05

Table 12: Diesel Generators A and E Simulated Vs Calculated Total Estimated Loading when U1 DBA & U2 Forced Shutdown with DG B Unavailable (at 60 Min & Beyond) - All ESF and Non-ESF Loads Considered.

		V_{Rated}		V_{min}		V_{Nom}		V_{Max}	
		DG A	DG E	DG A	DG E	DG A	DG E	DG A	DG E
f_{Rated}	kW	-42.75	16.45	-35.28	39.78	-54.97	8.86	-51.22	-123.93
	%	-1.10%	0.39%	-0.92%	0.96%	-1.41%	0.21%	-1.29%	-2.98%
f_{Min}	kW	-37.75	-46.30	-31.71	-31.13	-38.57	-59.28	-56.08	-81.80
	%	-1.00%	-1.16%	-0.85%	-0.79%	-1.01%	-1.45%	-1.46%	-2.01%
f_{Max}	kW	-47.53	-44.94	-28.92	-26.35	-45.71	-59.60	-60.94	-87.88
	%	-1.20%	-1.07%	-0.74%	-0.67%	-1.14%	-1.41%	-1.51%	-2.05%

NOTE: The percentage variation in DG kW loading is calculated with respect to ETAP results as $[1-(kW_{Calc}/kW_{ETAP})]x100$

Table 13: Percent Changes Between DGs Total Calculated Loads (kW) Vs ETAP Results – All ESF and Non-ESF Loads Considered

The figures of Exhibit 8 provide a graphical representation of selected electrical attributes for DGs A and E dynamic response under a postulated worst case scenario - Unit 1 DBA with Unit 2 Forced Shutdown and DG B unavailable. The subject exhibit includes the following plots:

Figure No.	Description
1	DG A Response - Case 1 Voltage, Frequency, Current
2	DG A Response - Case 1 kW and kVA
3	DG A Response - Case 3 Voltage, Frequency, Current
4	DG A Response - Case 3 kW and kVA
5	DG A Response - Case 5 Voltage, Frequency, Current
6	DG A Response - Case 5 kW and kVA
7	DG A Response - Case 7 Voltage, Frequency, Current
8	DG A Response - Case 7 kW and kVA
9	DG A Response - Case 9 Voltage, Frequency, Current
10	DG A Response - Case 9 kW and kVA
11	DG A Response - Case 11 Voltage, Frequency, Current
12	DG A Response - Case 11 kW and kVA
13	DG E Response - Case 13 Voltage, Frequency, Current
14	DG E Response - Case 13 kW and kVA
15	DG E Response - Case 15 Voltage, Frequency, Current
16	DG E Response - Case 15 kW and kVA
17	DG E Response - Case 17 Voltage, Frequency, Current
18	DG E Response - Case 17 kW and kVA
19	DG E Response - Case 19 Voltage, Frequency, Current
20	DG E Response - Case 19 kW and kVA
21	DG E Response - Case 21 Voltage, Frequency, Current
22	DG E Response - Case 21 kW and kVA
23	DG E Response - Case 23 Voltage, Frequency, Current
24	DG E Response - Case 23 kW and kVA

The following table outlines the ETAP Study Case files and scenario descriptions generated for the transient stability modeling of DGs A and E when operating with steady state frequency and voltage within Tech Specs acceptable limits (i.e. Voltage: 4000V – 4400V and Frequency: 59.3Hz – 60.5Hz):

Filename: DGs Model for RAIs

Case	Scenario Description	ETAP Study Case Details				
		Revision	Configuration	Study Case	Output Report	Module
1	Unit 1 LOCA and Unit 2 Forced Shutdown with DG A operating at steady state voltage of **4000V** and frequency of **59.3Hz.**	Base	YVES	RAI_DGA_Load	DGA Fmin&Vrated	Transient Stability Analysis
2	Unit 1 LOCA and Unit 2 Forced Shutdown with DG A operating at steady state voltage of **4160V** and frequency of **59.3Hz.**	Base	YVES	RAI_DGA_Load	DGA Fmin&Vnom	Transient Stability Analysis
3	Unit 1 LOCA and Unit 2 Forced Shutdown with DG A operating at steady state voltage of **4400V** and frequency of **59.3Hz.**	Base	YVES	RAI_DGA_Load	DGA Fmin&Vmax	Transient Stability Analysis
4	Unit 1 LOCA and Unit 2 Forced Shutdown with DG A operating at steady state voltage of **3793V** and frequency of **59.3Hz.**	Base	YVES	RAI_DGA_Load	DGA Fmin&Vmin	Transient Stability Analysis
5	Unit 1 LOCA and Unit 2 Forced Shutdown with DG A operating at steady state voltage of **4000V** and frequency of **60.0Hz.**	Base	YVES	RAI_DGA_Load	DGA F&Vrated	Transient Stability Analysis
6	Unit 1 LOCA and Unit 2 Forced Shutdown with DG A operating at steady state voltage of **4160V** and frequency of **60.0Hz.**	Base	YVES	RAI_DGA_Load	DGA Frated&Vnom	Transient Stability Analysis
7	Unit 1 LOCA and Unit 2 Forced Shutdown with DG A operating at steady state voltage of **4400V** and frequency of **60.0Hz.**	Base	YVES	RAI_DGA_Load	DGA Frated&Vmax	Transient Stability Analysis
8	Unit 1 LOCA and Unit 2 Forced Shutdown with DG A operating at steady state voltage of **3793V** and frequency of **60.0Hz.**	Base	YVES	RAI_DGA_Load	DGA Frated&Vmin	Transient Stability Analysis
9	Unit 1 LOCA and Unit 2 Forced Shutdown with DG A operating at steady state voltage of **4000V** and frequency of **60.5Hz.**	Base	YVES	RAI_DGA_Load	DGA Fmax&Vrated	Transient Stability Analysis
10	Unit 1 LOCA and Unit 2 Forced Shutdown with DG A operating at steady state voltage of **4160V** and frequency of **60.5Hz.**	Base	YVES	RAI_DGA_Load	DGA Fmax&Vnom	Transient Stability Analysis
11	Unit 1 LOCA and Unit 2 Forced Shutdown with DG A operating at steady state voltage of **4400V** and frequency of **60.5Hz.**	Base	YVES	RAI_DGA_Load	DGA Fmax&Vmax	Transient Stability Analysis
12	Unit 1 LOCA and Unit 2 Forced Shutdown with DG A operating at steady state voltage of **3793V** and frequency of **60.5Hz.**	Base	YVES	RAI_DGA_Load	DGA Fmax&Vmin	Transient Stability Analysis

Case	Scenario Description	ETAP Study Case Details				
		Revision	Configuration	Study Case	Output Report	Module
13	Unit 1 LOCA and Unit 2 Forced Shutdown with DG E operating at steady state voltage of **4000V** and frequency of **59.3Hz.**	Base	YVES_DGE	RAI_DGE_Load	DGE Fmin&Vrated	Transient Stability Analysis
14	Unit 1 LOCA and Unit 2 Forced Shutdown with DG E operating at steady state voltage of **4160V** and frequency of **59.3Hz.**	Base	YVES_DGE	RAI_DGE_Load	DGE Fmin&Vnom	Transient Stability Analysis
15	Unit 1 LOCA and Unit 2 Forced Shutdown with DG E operating at steady state voltage of **4400V** and frequency of **59.3Hz.**	Base	YVES_DGE	RAI_DGE_Load	DGE Fmin&Vmax	Transient Stability Analysis
16	Unit 1 LOCA and Unit 2 Forced Shutdown with DG E operating at steady state voltage of **3793V** and frequency of **59.3Hz.**	Base	YVES_DGE	RAI_DGE_Load	DGE Fmin&Vmin	Transient Stability Analysis
17	Unit 1 LOCA and Unit 2 Forced Shutdown with DG E operating at steady state voltage of **4000V** and frequency of **60.0Hz.**	Base	YVES_DGE	RAI_DGE_Load	DGE F&Vrated	Transient Stability Analysis
18	Unit 1 LOCA and Unit 2 Forced Shutdown with DG E operating at steady state voltage of **4160V** and frequency of **60.0Hz.**	Base	YVES_DGE	RAI_DGE_Load	DGE Frated&Vnom	Transient Stability Analysis
19	Unit 1 LOCA and Unit 2 Forced Shutdown with DG E operating at steady state voltage of **4400V** and frequency of **60.0Hz.**	Base	YVES_DGE	RAI_DGE_Load	DGE Frated&Vmax	Transient Stability Analysis
20	Unit 1 LOCA and Unit 2 Forced Shutdown with DG E operating at steady state voltage of **3793V** and frequency of **60.0Hz.**	Base	YVES_DGE	RAI_DGE_Load	DGE Frated&Vmin	Transient Stability Analysis
21	Unit 1 LOCA and Unit 2 Forced Shutdown with DG E operating at steady state voltage of **4000V** and frequency of **60.5Hz.**	Base	YVES_DGE	RAI_DGE_Load	DGE Fmax&Vrated	Transient Stability Analysis
22	Unit 1 LOCA and Unit 2 Forced Shutdown with DG E operating at steady state voltage of **4160V** and frequency of **60.5Hz.**	Base	YVES_DGE	RAI_DGE_Load	DGE Fmax&Vnom	Transient Stability Analysis
23	Unit 1 LOCA and Unit 2 Forced Shutdown with DG E operating at steady state voltage of **4400V** and frequency of **60.5Hz.**	Base	YVES_DGE	RAI_DGE_Load	DGE Fmax&Vmax	Transient Stability Analysis
24	Unit 1 LOCA and Unit 2 Forced Shutdown with DG E operating at steady state voltage of **3793V** and frequency of **60.5Hz.**	Base	YVES_DGE	RAI_DGE_Load	DGE Fmax&Vmin	Transient Stability Analysis

8.0 SUMMARY

This analysis evaluated the effects of DG frequency and voltage variations in the ranges of 59.3Hz to 60.5Hz and 4000V to 4400V respectively for major equipment fed by DGs following a Unit 1 DBA and Unit 2 Forced Shutdown with DG B Unavailable. Some of the main aspects examined included DG steady state loading, fuel oil consumption, and lube oil and jacket water systems. Additionally, the effects of DG frequency and voltage variations on motors, battery chargers, pumps and MOVs performance were also evaluated. It was confirmed via qualitative estimation and dynamic transient simulation that under the worst case design basis accident, the DGs loading when operating within the frequency and voltage ranges evaluated will not exceed their continuous ratings or fuel oil consumption rates when supplying required ESF loads and Non-ESF not manually initiated loads for mitigation of the worst case DBA. When considering all loads (ESF and all Non-ESF) per FSAR Table 8.3-3, DG E total loading results remain significantly below its rated continuous loading in all cases while DG A total loading results in four cases (4000V, 60.5Hz; 4160V, 60.5Hz; 4400V, 60.0Hz and 4400V, 60.5Hz) could slightly exceed (to a maximum ~2.6%) the DG's continuous rating of 4000kW. However several conservatisms, including accounting for two RHRSW pumps (~ 463kW) in operation when only one is needed for decay heat removal for both units (Reference Section 3.2) and non-ESF loads manually initiated (~ 465kW for DG A loads at 60 Minutes & Beyond) that are not required for the mitigation of Unit 1 DBA and Unit 2 Forced Shutdown were explicitly added to the DG loading in this analysis to yield bounding results. As a result, approximately 928kW (23.2% of the DG continuous rating) are conservatively added to the total loading results and the corresponding 23.2% margin is substantially greater than the 2.6% above.

By removing Non-ESF loads[15] that are manually initiated and still maintaining ample loading margin by accounting for RHRSW load (~463kW or ~ 11.5% of DG A continuous rating), DGs A and E total loadings as depicted in Table 8 remain below their respective continuous rating with adequate additional margins (~ 9.8% and ~ 22.5% for DGs A and E respectively) for all DG steady state voltage and frequency variations within the ranges evaluated.

8.1 EVALUATION OF RESULTS AGAINST ACCEPTANCE CRITERIA

Table 14 below summarizes the evaluation of the qualitative approach and ETAP results against the acceptance criteria listed in Section 1.1. All results meet the set of acceptance criteria.

[15] See Reference 6.1.9 Note 12

Acceptance Criteria No.	Criteria Description	Results Evaluation Vs Acceptance Criteria
AC1	The continuous loading of DG A and E at extreme voltage and frequency tolerances, 4000kW and 5000kW respectively, are greater than the sum of conservatively estimated Engineered Safety Features (ESF) loads and Non-ESF not manually initiated loads needed to be supplied following a Unit 1 design basis Accident, Unit 2 Forced Shutdown and DG B Unavailable (FSAR Table 8.3-3)	DG A and E total loading when Unit 1 DBA and Unit 2 Forced Shutdown with DG B unavailable without Non-ESF loading manually initiated is lower than their respective continuous ratings for voltage and frequency variations within analyzed ranges. As shown in Table 8, the maximum loading for both DGs is at operation under maximum steady state voltage and frequency (4400V, 60.5Hz). The corresponding loading of approximately 3609kW and 3874kW for DG A and E respectively are below their continuous ratings with adequate margins and conservatism. Therefore, AC1 is met.
AC2	DG A and E are capable of starting and accelerating all ESF and forced shutdown loads.	ETAP transient stability analysis results of the effects of DG steady state voltage and frequency variations shows that DG A and E are both capable of starting and accelerating all four major motors loads dynamically modeled. These motor loads represent the largest motors started and accelerated for the mitigation of the worst case DBA event evaluated. Exhibit 8 provides a time domain dynamic response plots of key electrical characteristics for DG A and E. As such, AC2 is met.
AC3	DG A and E voltage and frequency are capable of recovery from transients caused by step load increases.	ETAP modeling of DGs shows as illustrated by the time domain plots of voltage and frequency that the DG voltage and frequency recover for all cases from transients caused by step load increases. The DG steady state voltage and frequency recover in all case to its initial postulated steady state value prior to load sequencing. See Exhibit 8 for DG voltage and frequency plots. AC3 is met.
AC4	The qualitative analysis results must be demonstrated to reasonably match (within ±3%) the ETAP transient analysis model results for each case. ETAP is an Appendix B software and its results are deemed more realistic since it accounts for the transient response of the circuits which the qualitative approach does not.	Table 13 calculates the changes in % between DGs total loads (kW) determined per the qualitative approach described in Section 7.3 and ETAP results documented in Section 7.9. The subject percentage variation in DG loading is calculated with respect to ETAP results since they are expected to be more realistic. Table 13 shows that the maximum percentage variation in total loading results is - 2.98% for DG E under rated frequency and maximum voltage (60Hz, 4400V). For all the cases, the results from the qualitative approach match ETAP results within the established tolerance. Therefore, criterion AC4 is met.

AC5	DGs operation within the allowable TS voltage and frequency ranges does not adversely impact the capability of safety related components required to perform their design functions to mitigate the effects of a design basis accident.	DG voltage and frequency variations within analyzed ranges were evaluated against lowest margin flow systems credited in the safety analysis per Reference 6.4.21. The subject reference concluded that the flow rates used in the LOCA analysis remain conservative even when considering DG operation at minimum voltage and frequency. As discussed under Section 7.0, safety related components required to perform their design function to mitigate the effects of a DBA will not be adversely affected by DG operation within the analyzed voltage and frequency ranges. Therefore, criterion AC5 is met.

Table 14: Evaluation Acceptance Criteria Vs. Results

9.0 ATTACHMENTS & EXHIBITS

Attachments	Descriptions	No. Pages
9.1 Starts on Pg. 65	DG A Transient Stability Model Topography	1
9.2 Starts on Pg. 66	DG E Transient Stability Model Topography	1
9.3 Starts on Pg. 67	Case 1 ETAP Transient Stability Summary Report	742
9.4 Starts on Pg. 809	Case 2 ETAP Transient Stability Summary Report	742
9.5 Starts on Pg. 1551	Case 3 ETAP Transient Stability Summary Report	742
9.6 Starts on Pg. 2293	Case 4 ETAP Transient Stability Summary Report	742
9.7 Starts on Pg. 3035	Case 5 ETAP Transient Stability Summary Report	742
9.8 Starts on Pg. 3777	Case 6 ETAP Transient Stability Summary Report	742
9.9 Starts on Pg. 4519	Case 7 ETAP Transient Stability Summary Report	742
9.10 Starts on Pg. 5261	Case 8 ETAP Transient Stability Summary Report	742
9.11 Starts on Pg. 6003	Case 9 ETAP Transient Stability Summary Report	742
9.12 Starts on Pg. 6745	Case 10 ETAP Transient Stability Summary Report	742
9.13 Starts on Pg. 7487	Case 11 ETAP Transient Stability Summary Report	742
9.14 Starts on Pg. 8229	Case 12 ETAP Transient Stability Summary Report	742
9.15 Starts on Pg. 8971	Case 13 ETAP Transient Stability Summary Report	851
9.16 Starts on Pg. 9822	Case 14 ETAP Transient Stability Summary Report	851

Attachments	Descriptions	No. Pages
9.17 Starts on Pg. 10673	Case 15 ETAP Transient Stability Summary Report	851
9.18 Starts on Pg. 11524	Case 16 ETAP Transient Stability Summary Report	851
9.19 Starts on Pg. 12375	Case 17 ETAP Transient Stability Summary Report	851
9.20 Starts on Pg. 13226	Case 18 ETAP Transient Stability Summary Report	851
9.21 Starts on Pg. 14077	Case 19 ETAP Transient Stability Summary Report	851
9.22 Starts on Pg. 14928	Case 20 ETAP Transient Stability Summary Report	851
9.23 Starts on Pg. 15779	Case 21 ETAP Transient Stability Summary Report	851
9.24 Starts on Pg. 16630	Case 22 ETAP Transient Stability Summary Report	851
9.25 Starts on Pg. 17481	Case 23 ETAP Transient Stability Summary Report	851
9.26 Starts on Pg. 18332	Case 24 ETAP Transient Stability Summary Report	851
9.27 Starts on Pg. 19183	Diesel Generator Fuel Oil Flow Velocity	1

			DG A Demand kW					
			0 - 10 Minutes		10 - 60 Minutes		60 Minutes & Beyond	
Equipment No.	Loads	Number Connected	kW-Constant Z	kW-Constant VA	kW-Constant Z	kW-Constant VA	kW-Constant Z	kW-Constant VA
1V211 A	Core Spray Pump Room Unit Coolers	1	-	2	-	2	-	2
1V222 A	Engineered Safeguards Switchgear & L.C. Unit Coolers	1	-	13	-	13	-	13
1V210 A,	RHR Pump Room Unit Coolers	1	-	9	-	9	-	9
1V208 A	RCIC Pump Room Unit Coolers	1	-	1.5	-	1.5	-	1.5
1D613	Battery Chargers, 125V DC	1	16	-	16	-	16	-
1Y216	120V Instrument, A.C. Dist. Panels	1	24	-	24	-	24	-
1D635 A	Battery Chargers, 250 D.C.	1	56	-	56	-	56	-
1E440 A,	Containment Hydrogen Recombiners	1	-	-	-	-	-	75
1V506 A	RHR Service Water Pump House Supply Fans (RHRSWP)	1	-	-	-	4.6	-	4.6
1S246	LPCI Swing Bus Isolation System M-G Sets	1	-	13	-	13	-	13
1X210,	Engineered Safeguards Load Center Transformer Losses	1	15	-	15	-	15	-
	Unit 2 Forced Shutdown Load							
2V222 A	Engineered Safeguards Switchgear & L.C. Unit Coolers	1	-	13	-	13	-	13
2V208 A	RCIC Pump Room Unit Coolers	1	-	1.5	-	1.5	-	1.5
2D613,	Battery Chargers, 125V D.C.	1	16	-	16	-	16	-
2Y216	120V Instrument A.C. Dist Panels	1	24	-	24	-	24	-
2D653 A,	Battery Chargers, 250V D.C.	1	20	-	20	-	20	-
2K210 A	Compressor Motor for Emergency SWGR and L.C. Room Cooling	1	-	48	-	48	-	48
2S246,	LPCI Swing Bus Isolation System M-G Sets	1	-	13	-	13	-	13
2X210	Engineered Safeguards Load Center Transformer Losses	1	15	-	15	-	15	-
	Unit 1 and 2 Common Loads							
OV512 A,B,C,D	Diesel Generator Room Ventilation Supply Fans	1	-	33	-	33	-	33
OV514 A,B,C,D	Diesel Generator Diesel Oil Transfer Pumps	1	-	2.5	-	2.5	-	2.5
OV201 A,B	Reactor Building Recir. Fans	1	-	61	-	61	-	61
OK507 A1, A2 B1, B2 C1, C2, D1, D2	Diesel Generator Starting Air Compressors	2	-	18	-	-	-	-
OV521 A,B,C,D	Engineered Safeguards Service Water Pump House Supply Fans	2	-	9	-	9	-	9
OC577 A,B,C,D	Diesel Generator HVAC Panels	1	4	-	4	-	4	-
OC578, 579	ESSW Pump House HVAC Control Panels	1	3.8	-	3.8	-	3.8	-
OE525 A,B,C,D	Diesel Generator Lube Oil Heaters	1	9	-	0	-	-	-
	4.16 kV Cable Losses		11.75	-	11.75	-	11.75	-
			-------	----------	-------	----------	-------	----------
	ESF Loads. Total		214.6	237.5	205.6	224.1	205.6	299.1
	Non-ESF Loads							
2P111, 1P111	Turbine Generator Turning Gear Oil PP	1	-	32	-	32	-	32
2P132A	CRD Water Pumps. Unit 2 Essential Lighting	1	-	-	-	215	-	163
		Set	96	-	96	-	96	-
1P/2P109 – A-H,J 1S/2S103,104	Turbine Generator Bearing Lift Pump & Turning Gear	1	-	-	-	119	-	119
1K/2K107A,B 1P/2P103A,B	Instrument Air Compressors Turbine Bldg. Cooling Water Pumps	1	-	-	-	82	-	82
		2	-	26	-	26	-	26
1P/2P210 A,B	Reactor Bldg. Close Cooling Wtr. PP. 1	1	-	25	-	25	-	25
1S/2S106 A,B,C	RFPT Turning Gear	3	-	-	-	4.8	-	4.8
1X291 B/2X291 A,B 1X/2X290	Standby Liquid & Oxygen And Hydrogen Analyzer Heat Tracing Panels	3	21	-	21	-	21	-
1K/2K104	Main Turbine L.O. Reservoir Oil Mist Eliminator	1	-	6	-	6	-	6
1K/2K105	Main Turbine L.O. Reservoir Oil Mist Eliminator	1	-	2.4	-	2.4	-	2.4
OX201,203,211, 213	Engineered Safeguards Transformer Auxiliaries	1	2.8	-	-	-	-	-
1X800, 1X801	UPS/SPDS Distribution Panels	1	5	-	5	-	5	-
1PP100	30KVA Transformer/Post Accident Vent Stack Monitoring & Sampling Pumps	1	-	30	-	35	-	35
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	Non-ESF Loads, Total		124.8	121.4	122.0	547.2	122.0	495.2
	TOTAL LUMPED LOAD		339.4	358.9	327.6	771.3	327.6	794.3
			48.6%	51.4%	29.8%	70.2%	29.2%	70.8%

	0 - 10 Minutes		10 - 60 Minutes		60 Minutes & Beyond	
	kW-Constant Z	kW-Constant VA	kW-Constant Z	kW-Constant VA	kW-Constant Z	kW-Constant VA
U2 FORCED SHUTDOWN LUMPED LOAD	75	75.5	75	75.5	75	75.5
	49.8%	50.2%	49.8%	50.2%	49.8%	50.2%
TOTAL	150.5		150.5		150.5	
U1 DBA LUMPED LOADS	264.4	283.4	252.6	695.8	252.6	718.8
	48.3%	51.7%	26.6%	73.4%	26.0%	74.0%
TOTAL	547.8		948.4		971.4	

Exhibit 1: DG A Lumped Loading for Unit 1 DBA and Unit 2 Forced Shutdown with DG B Unavailable.

		Diesel Generator E Substituted for Diesel Generator A						
			0 - 10 Minutes		10 - 60 Minutes		60 Minutes & Beyond	
Equipment No.	Loads	Number Connected	kW-Constant Z	kW-Constant VA	kW-Constant Z	kW-Constant VA	kW-Constant Z	kW-Constant VA
	Total Diesel A Lumped Load		339.4	358.9	327.6	771.3	327.6	794.3
Diesel Generator B, C & D Loads Affected by Diesel Generator E Substitution								
OP514 A,B,C,D	Diesel Generator Diesel Oil Transfer Pumps	1	-	(2.5)	-	(2.5)	-	(2.5)
OK507 A1,A2,B1, B2	Diesel Generator Starting Air Compressors	2	-	(18)	-	-	-	-
OE508 A,B,C,D	Diesel Generator Jacket Water Heaters	1	15	-	15	-	15	-
OE525 A,B,C,D	Diesel Generator Lube Oil Heaters	1	-	-	9	-	9	-
OE570 A,B,C,D	Diesel Generator Space Heaters	1	4.5	-	4.5	-	4.5	-
OP530 A,B,C,D	Diesel Generator Jacket Water Circulating Pumps	1	-	4.5	-	4.5	-	4.5
OP532 A,B,C,D	Diesel Generator Pre-Lube Pumps	1	-	9	-	9	-	9
Diesel Generator E Loads								
OV512 E1,E2	Diesel Generator E Room Ventilation Supply Fans	2	-	60	-	60	-	60
OV512 E3,E4	Diesel Generator ERoom Ventilation Exhaust Fans	2	-	60	-	60	-	60
OP514 E	Diesel Generator E Diesel Oil Transfer Pump	1	-	2	-	2	-	2
OD596	Diesel Generator E Battery Charger	1	20	-	20	-	20	-
OV511 E	Diesel Generator E Battery Room Exhaust Fan	1	-	2	-	2	-	2
OY565	Diesel Generator E Distribution Panel	1	15	-	15	-	15	-
OLP5B	Diesel Generator E Essential Lighting Panel	1	30	-	30	-	30	-
OX565	Diesel Generator E Transformer Losses	1	10	-	10	-	10	-
			-------	-------	-------	-------	-------	-------
			94.5	117.0	103.5	135.0	103.5	135.0
	4.16 kV Cable Losses Net (E - A)		2.8	-	2.8	-	2.8	-
	TOTAL DIESEL E LUMPED LOAD		436.6	475.9	433.8	906.3	433.8	929.3
			47.8%	52.2%	32.4%	67.6%	31.8%	68.2%

Exhibit 2: Diesel Generator E Substituted to DG A for Unit 1 DBA and Unit 2 Forced Shutdown with DG B Unavailable – Lumped Loading

Table 11.5 —Approximate Effect of Voltage and Frequency Variation on Integral HP Motors

	Voltage		Frequency	
Characteristics	**110%**	**90%**	**105%**	**95%**
Torque, starting and breakdown	Increase 21%	Decrease 19%	Decrease 10%	Decrease 11%
Speed:				
Synchronous	No change	No change	Increase 5%	Decrease 5%
Full load	Increase 1%	Decrease 1.5%	Increase 5%	Decrease 5%
Full load effeciency	Increase 4–6 points	Decrease 2 points	Slight Increase	Slight decrease
Full load power factor	Decrease 4 points	Increase 1 points	Slight Increase	Slight decrease
Currents:				
Starting	Increase 10–12%	Decrease 10–12%	Decrease 5–6%	Increase 5–6%
Full load	Decrease 6%	Increase 10%	Slight decrease	Slight increase

Exhibit 3: IEEE Std 666-1991 Table 11.5 - Approximate effect of Voltage and Frequency Variation on Integral HP Motors

Table 11.6 — Approximate Effect of Voltage and Frequency Variation on Large Motors[23]

Characteristics	Voltage 110%	Voltage 90%	Frequency 105%	Frequency 95%
Torque*				
Starting and maximum running	Approximate increase 21%	Approximate decrease 19%	Decrease 10%	Increase 11%
Speed†				
Synchronous	No Change	No Change	Increase 5%	Decrease 5%
Full load	Increase 0.1–1.25%	Decrease 0.13–1.5%	Increase 5%	Decrease 5%
Percent Slip	Decrease 16–24%	Increase 20–30%	Little Change	Little Change
Efficiency				
Full load	Decrease of 2.0 to increase of 0.5 points	No change to decrease of 1.5 points	Slight increase	Slight decrease
3/4 load	Decrease of 0.1–4.0 points	Decrease of 0.2 to increase 1.0 points	Slight increase	Slight decrease
1/2 load	Decrease of 0.5–4.0 points	Increase 0.1–3.00 points	Slight increase	Slight decrease
Power factor				
Full load	Decrease of 2–8 points	Increase of 0.5–5 points	Slight increase	Slight decrease
3/4 load	Decrease of 6–10 points	Increase of 2–7 points	Slight increase	Slight decrease
1/2 load	Decrease of 9–12 points	Increase of 4–10 points	Slight increase	Slight decrease
Current				
Starting	Increase of 10–12 points	Decrease 10–12 points	Decrease 5–6 %	Increase 5–6 %
Full load	Increase of 4% to decrease of 7%	Increase of 5–11%	Slight decrease	Slight increase
Temperature	Increase of 5% to decrease of 8%	Increase of 5–20%	Slight decrease	Slight increase
Maximum overload capacity	Increase of 21%	Decrease 19%	Slight decrease	Slight increase
Magnetic noise	Slight increase	Slight decrease	Slight decrease	Slight increase

Courtesy of General Electric Company

*The starting and maximum running torque of ac induction motors will vary approximately as the square of the voltage.
†The speed of ac induction motors will vary directly with the frequency.

Exhibit 4: IEEE Std 666-1991 Table 11.6 - Approximate Effect of Voltage and Frequency Variation on Large Motors

Loads	Frequency (Hz)			Voltage (V)				Rated Speed	S_{synch}	# Poles
	f_{Rated}	f_{Min}	f_{Max}	V_{Rated}	V_{Min1}	V_{Nom}	V_{Max}	S_1 (rpm)		
Reactor Core Spray Pumps	60	59.3	60.5	4000	3793	4160	4400	1780	1800	4
RHR Pumps	60	59.3	60.5	4000	3793	4160	4400	1185	1200	6
RHR Service Water Pumps	60	59.3	60.5	4000	3793	4160	4400	1180	1200	6
Emergency Service Water Pumps	60	59.3	60.5	4000	3793	4160	4400	1775	1800	4

		ΔS (rpm)				Resulting Speed $S_2 = S_1 - \Delta S$ (rpm)				$(S2/S1) = 1 - (\Delta S/S1)$				HP2 = (f2/f1)^3*HP1 (Affinity Laws)			
		V_{Rated}	V_{Min1}	V_{Nom}	V_{Max}	V_{Rated}	V_{Min1}	V_{Nom}	V_{Max}	V_{Rated}	V_{Min1}	V_{Nom}	V_{Max}	V_{Rated}	V_{Min1}	V_{Nom}	V_{Max}
Freq (Hz)	f_{Rated}	0	2.24	-1.509	-3.47	1780	1778	1782	1783	100.0%	99.874%	100.08%	100.20%	100.0%	99.62%	100.25%	100.59%
		0	1.68	-1.132	-2.60	1185	1183	1186	1188	100.0%	99.858%	100.10%	100.22%	100.00%	99.57%	100.29%	100.66%
		0	2.24	-1.509	-3.47	1180	1178	1182	1183	100.0%	99.810%	100.13%	100.29%	100.00%	99.43%	100.38%	100.89%
		0	2.80	-1.886	-4.34	1775	1772	1777	1779	100.0%	99.842%	100.11%	100.24%	100.00%	99.53%	100.32%	100.74%
	Average													100.00%	99.54%	100.31%	100.72%
	f_{Min}	20.30	22.49	18.83	16.91	1760	1758	1761	1763	98.859%	98.736%	98.942%	99.050%	96.62%	96.26%	96.86%	97.18%
		13.48	15.12	12.37	10.93	1172	1170	1173	1174	98.863%	98.724%	98.956%	99.077%	96.63%	96.22%	96.90%	97.26%
		13.30	15.49	11.83	9.91	1167	1165	1168	1170	98.873%	98.687%	98.998%	99.160%	96.66%	**96.11%**	97.02%	97.50%
		20.13	22.87	18.29	15.89	1755	1752	1757	1759	98.866%	98.712%	98.970%	99.105%	96.64%	96.18%	96.94%	97.34%
	Average													96.63%	96.19%	96.93%	97.32%
	f_{Max}	-14.50	-12.22	-16.03	-18.03	1794	1792	1796	1798	100.81%	100.69%	100.90%	101.01%	102.46%	102.07%	102.73%	103.07%
		-9.62	-7.91	-10.77	-12.27	1195	1193	1196	1197	100.81%	100.67%	100.91%	101.04%	102.46%	102.02%	102.75%	103.14%
		-9.50	-7.22	-11.03	-13.03	1189	1187	1191	1193	100.80%	100.61%	100.93%	101.10%	102.43%	101.85%	102.83%	**103.35%**
		-14.37	-11.52	-16.29	-18.78	1789	1787	1791	1794	100.81%	100.65%	100.92%	101.06%	102.45%	101.96%	102.78%	103.21%
	Average													102.45%	101.97%	102.77%	103.19%

Exhibit 5: Speed & HP Variation Matrix of Major Motor Loads

		fRated &				fMin &				fMax &			
		VRated	VMin1	VNom	VMax	VRated	VMin1	VNom	VMax	VRated	VMin1	VNom	VMax
Generation Category		Min SS Volt	Min SS Old	Emergency	Max SS Volt	Min SS Volt	Min SS Old	Emergency	Max SS Volt	Min SS Volt	Min SS Old	Emergency	Max SS Volt
Loading Category		FL Reject	Accident	Emergency	DGA/E SURV Tes	FL Reject	Accident	Emergency	DGA SURV Tes	FL Reject	Accident	Emergency	DGA SURV Tes
U1 DBA Lumped Loads	Const kVA	100	100	100	100	100	100	100		100	100	100	100
	Const Z	0	0	0	0	0	0	0		0	0	0	0
	%Loading	100%	100%	100%	100%	100%	100%	100%		100%	100%	100%	100%
U1 DBA Static Load	%Loading	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	Load kW	226	226	226	226	226	226	226	226	226	226	226	226
U2 FSD Lumped Loads	Const kVA	100	100	100	100	100	100	100	100	100	100	100	100
	Const Z	0	0	0	0	0	0	0	0	0	0	0	0
	%Loading	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
U2 FSD Static Loads	%Loading	100%	100%	100%	100%	100%	100%	100%		100%	100%	100%	100%
	Load kW	60	60	60	60	60	60	60		60	60	60	60
% Loading Mtr Loads	RHR	89.90%	89.50%	90.20%	90.50%	86.80%	86.40%	87.05%	87.30%	92.15%	91.72%	92.42%	92.75%
	CS	98.75%	98.38%	99.00%	99.40%	95.35%	95.00%	95.60%	95.92%	101.25%	100.84%	101.50%	101.83%
	ESW	97.84%	97.35%	98.20%	98.60%	94.46%	94.05%	94.75%	95.18%	100.29%	99.80%	100.62%	101.10%
	RHRSW	95.64%	95.10%	96.00%	96.50%	92.40%	91.83%	92.75%	93.20%	98.02%	97.45%	98.40%	98.90%
Output file Name		DGA F&Vrated	DGA Frated&Vmin	DGA Frated&Vnom	DGA Frated&Vmax	DGA Fmin&Vrated	DGA Fmin&Vmin	DGA Fmin&Vnom	DGA Fmin&Vmax	DGA Fmax&Vrated	DGA Fmax&Vmin	DGA Fmax&Vnom	DGA Fmax&Vmax
DG E STATIC LOAD	%Loading	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	Load kW	74	74	74	74	74	74	74	74	74	74	74	74
DG E Lumped Loads	Const kVA	100	100	100	100	100	100	100	100	100	100	100	100
	Const Z	0	0	0	0	0	0	0	0	0	0	0	0
	%Loading	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Output file Name		DGE F&Vrated	DGE Frated&Vmin	DGE Frated&Vnom	DGE Frated&Vmax	DGE Fmin&Vrated	DGE Fmin&Vmin	DGE Fmin&Vnom	DGE Fmin&Vmax	DGE Fmax&Vrated	DGE Fmax&Vmin	DGE Fmax&Vnom	DGE Fmax&Vmax

NOTE: frated = 60.0Hz; fmin = 59.3Hz; fmax = 60.5Hz; Vrated = 4000V; Vmin1=3793V; Vnom=4160V; Vmax=4400V

Exhibit 6: ETAP Transient Stability - Study Case Information

DIESEL GENERATOR TOTAL ESF LOADING WITH DG B UNAVAILABLE; UNIT 1 DBA AND UNIT 2 FORCED SHUTDOWN

DESCRIPTION		0 - 10 Minutes			10 - 60 Minutes			60 Minutes & Beyond		
		DG A	DG C	DG D	DG A	DG C	DG D	DG A	DG C	DG D
Unit 1 Total DBA Loads	Rated Freq	2142.3	2122.5	2062.1	2146.9	1147.5	70.1	2221.9	1234.5	70.1
	Min Freq	2068.1	2049.1	1990.8	2072.6	1107.8	67.7	2145.0	1191.8	67.7
	Max Freq	2196.3	2176.0	2114.1	2201.0	1176.4	71.9	2277.9	1265.6	71.9
Unit 2 Total Forced Shutdown Loads	Rated Freq	150.5	149.6	115.2	613.5	149.6	1553.2	613.5	149.6	1553.2
	Min Freq	145.3	144.4	111.2	592.3	144.4	1499.5	592.3	144.4	1499.5
	Max Freq	154.3	153.4	118.1	629.0	153.4	1592.4	629.0	153.4	1592.4
Unit 1 & Unit 2 Total Common Loads	Rated Freq	497.3	1206.4	600.5	470.3	1179.4	573.5	470.3	1179.4	573.5
	Min Freq	480.1	1164.7	579.7	454.0	1138.6	553.7	454.0	1138.6	553.7
	Max Freq	509.8	1236.8	615.6	482.2	1209.1	588.0	482.2	1209.1	588.0
Total ESF Loads	**Rated Freq**	**2790.1**	**3478.5**	**2777.8**	**3230.7**	**2476.5**	**2196.8**	**3305.7**	**2563.5**	**2196.8**
	Min Freq	**2693.5**	**3358.1**	**2681.7**	**3118.9**	**2390.8**	**2120.8**	**3191.3**	**2474.8**	**2120.8**
	Max Freq	**2860.4**	**3566.2**	**2847.9**	**3312.1**	**2538.9**	**2252.2**	**3389.0**	**2628.1**	**2252.2**
Non - ESF Loads	*Rated Freq*	*258.0*	*159.9*	*217.6*	*681.0*	*146.0*	*300.5*	*629.0*	*221.0*	*364.5*
	Min Freq	*249.0*	*154.3*	*210.1*	*657.4*	*140.9*	*290.1*	*607.2*	*213.3*	*351.9*
	Max Freq	*264.5*	*163.9*	*223.1*	*698.1*	*149.7*	*308.1*	*644.8*	*226.6*	*373.7*
Total DG Loads	Rated Freq	3048.0	3638.4	2995.5	3911.6	2622.5	2497.4	3934.6	2784.5	2561.4
	Min Freq	2942.6	3512.5	2891.8	3776.3	2531.7	2411.0	3798.5	2688.1	2472.8
	Max Freq	3124.8	3730.1	3071.0	4010.2	2688.6	2560.3	4033.8	2854.7	2625.9

NOTE: DG loading estimation based on FSAR Table 8.3-3 Rev.57. Loads simplistically assumed all inductive with the following relationship used:

Rated Freq= 60Hz Min Freq = 59.3Hz Max Freq = 60.5Hz

$$kW_2 = kW_1 \, x \left(f_2/f_1\right)^3$$

DIESEL GENERATOR E TOTAL ESF LOADING WITH DG B UNAVAILABLE; UNIT 1 DBA AND UNIT 2 FORCED SHUTDOWN

DESCRIPTION		0 - 10 Minutes DG E Substituted for:			10 - 60 Minutes DG E Substituted for:			60 Minutes & Beyond DG E Substituted for:		
		DG A	DG C	DG D	DG A	DG C	DG D	DG A	DG C	DG D
Unit 1 Total DBA Loads	Rated Freq	2344.8	2325.0	2260.2	2376.4	1377.0	295.2	2451.4	1464.0	295.2
	Min Freq	2263.7	2244.6	2182.0	2294.2	1329.3	284.9	2366.6	1413.3	284.9
	Max Freq	2403.9	2383.6	2317.1	2436.3	1411.7	302.6	2513.2	1500.9	302.6
Unit 2 Total Forced Shutdown Loads	Rated Freq	150.5	149.6	115.2	613.5	149.6	1553.2	613.5	149.6	1553.2
	Min Freq	145.3	144.4	111.2	592.3	144.4	1499.5	592.3	144.4	1499.5
	Max Freq	154.3	153.4	118.1	629.0	153.4	1592.4	629.0	153.4	1592.4
Unit 1 & Unit 2 Total Common Loads	Rated Freq	497.3	1206.4	600.5	470.3	1179.4	573.5	470.3	1179.4	573.5
	Min Freq	480.1	1164.7	579.7	454.0	1138.6	553.7	454.0	1138.6	553.7
	Max Freq	509.8	1236.8	615.6	482.2	1209.1	588.0	482.2	1209.1	588.0
Total ESF Loads	**Rated Freq**	**2992.6**	**3681.0**	**2975.9**	**3460.2**	**2706.0**	**2421.9**	**3535.2**	**2793.0**	**2421.9**
	Min Freq	**2889.1**	**3553.6**	**2872.9**	**3340.5**	**2612.4**	**2338.1**	**3412.9**	**2696.4**	**2338.1**
	Max Freq	**3068.0**	**3773.8**	**3050.9**	**3547.4**	**2774.2**	**2482.9**	**3624.3**	**2863.4**	**2482.9**
Non - ESF Loads	Rated Freq	258.0	159.9	217.6	681.0	146.0	300.5	629.0	221.0	364.5
	Min Freq	249.0	154.3	210.1	657.4	140.9	290.1	607.2	213.3	351.9
	Max Freq	264.5	163.9	223.1	698.1	149.7	308.1	644.8	226.6	373.7
Total DG Loads	Rated Freq	3250.5	3840.9	3193.5	4141.1	2852.0	2722.4	4164.1	3014.0	2786.4
	Min Freq	3138.1	3708.0	3083.0	3997.9	2753.3	2628.2	4020.1	2909.7	2690.0
	Max Freq	3332.5	3937.7	3274.0	4245.5	2923.9	2791.0	4269.1	3089.9	2856.6

NOTE: DG loading estimation based on FSAR Table 8.3-3a Rev.55. Loads simplistically assumed all inductive with the following relationship used:

Rated Freq= 60Hz Min Freq = 59.3Hz Max Freq = 60.5Hz

$$kW_2 = kW_1 \, x \left(f_2/f_1\right)^3$$

Exhibit 7: DGs A, C, D and E Total Loading with DG B Unavailable; Unit 1 DBA and Unit 2 Forced Shutdown.

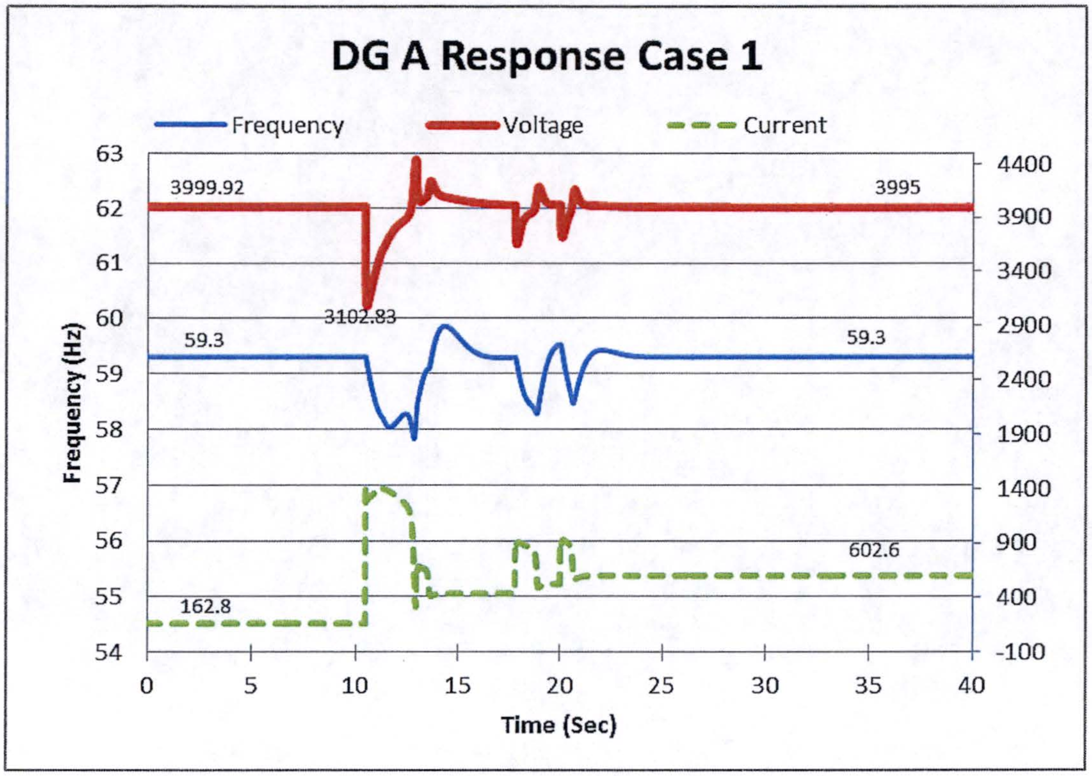

Figure 1: DG A Response Case 1 Voltage, Frequency, Current

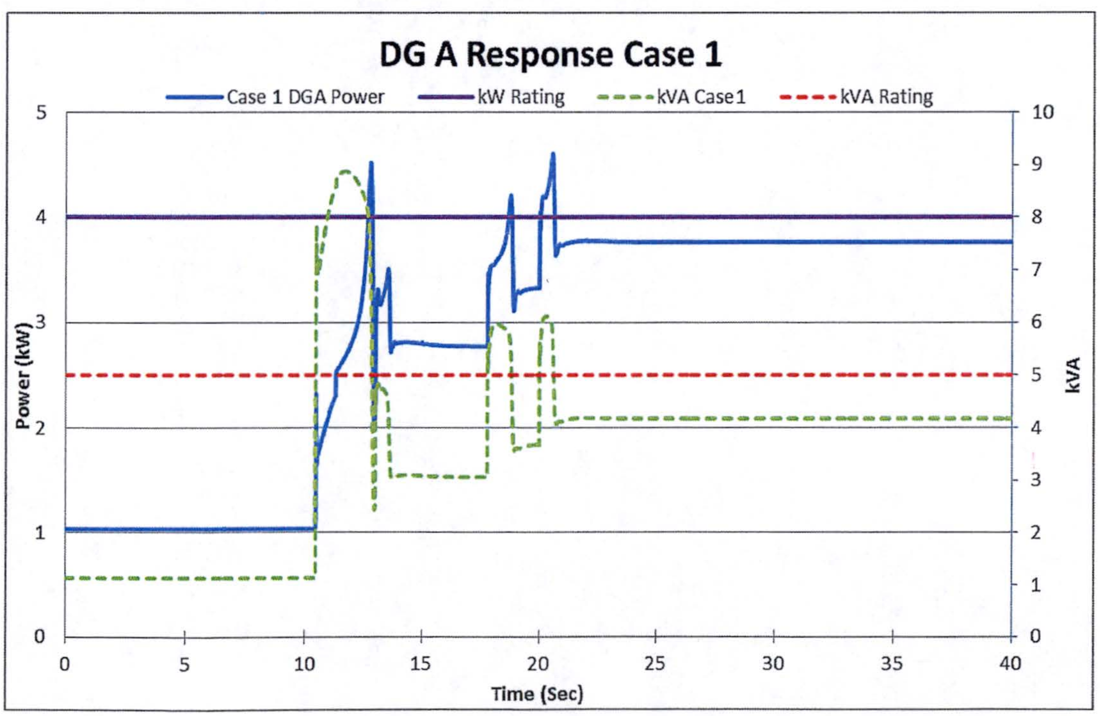

Figure 2: DG A Response - Case 1 kW and kVA

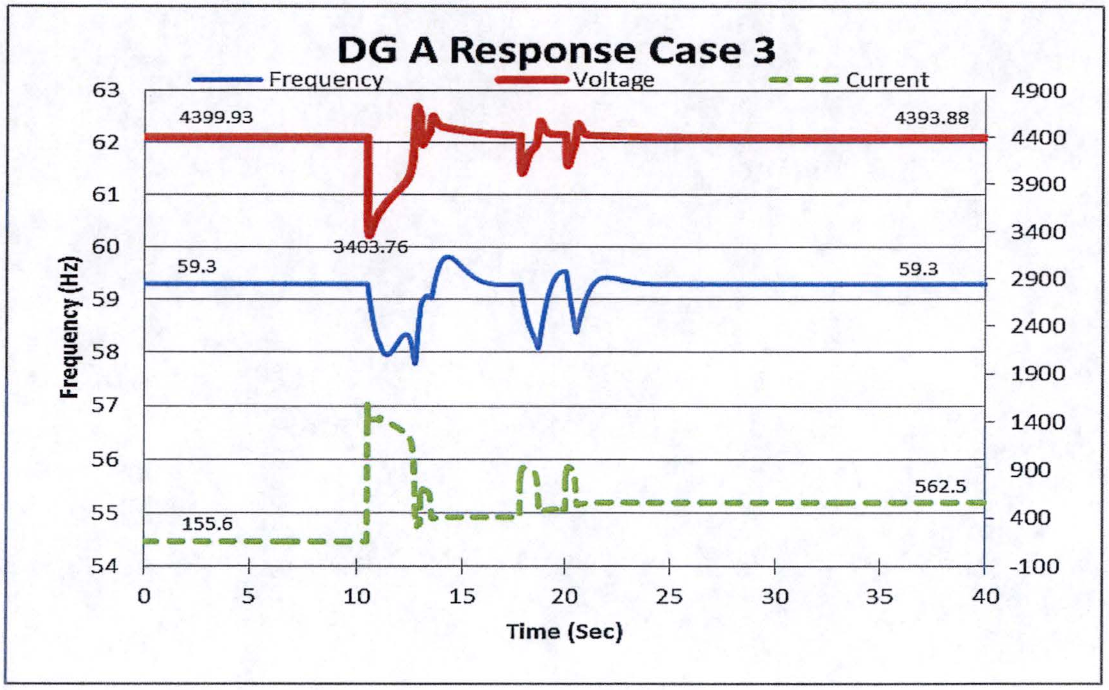

Figure 3: DG A Response Case 3 Voltage, Frequency, Current

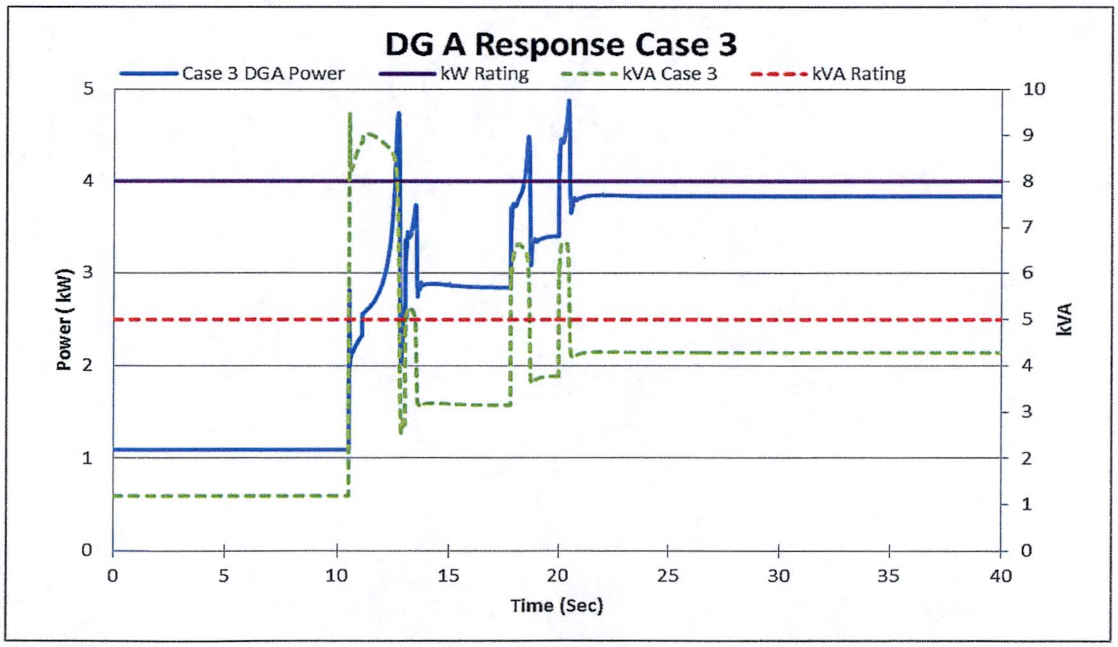

Figure 4: DG A Response - Case 3 kW and kVA

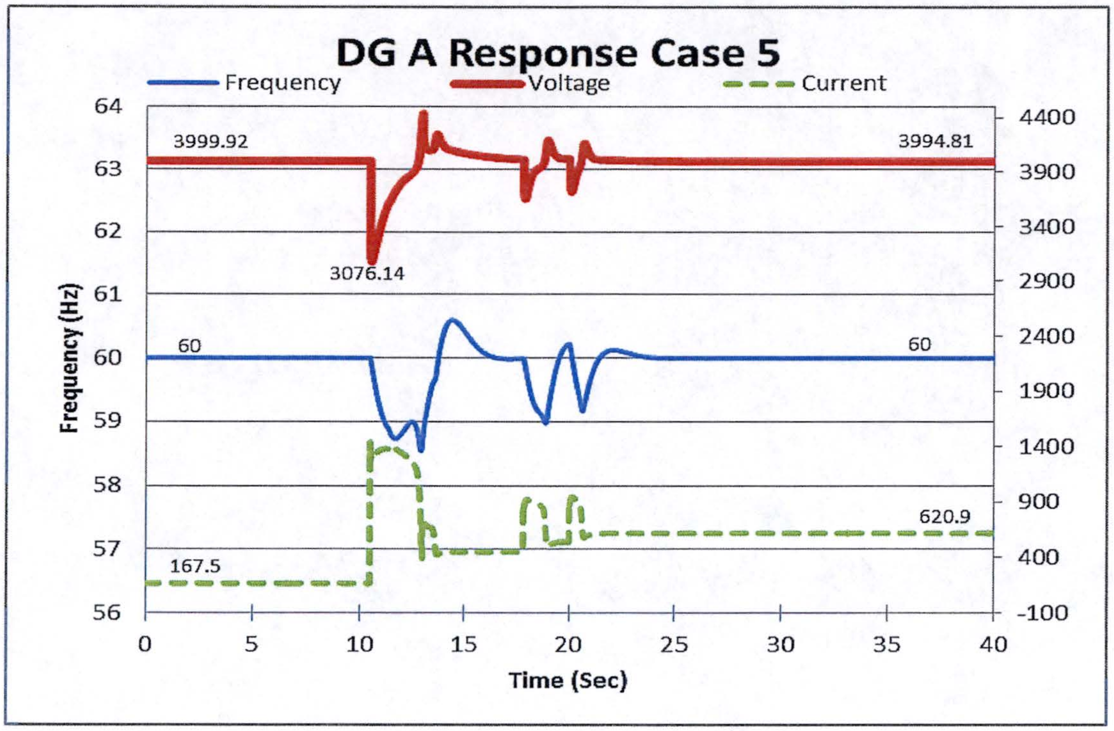

Figure 5: DG A Response Case 5 Voltage, Frequency, Current

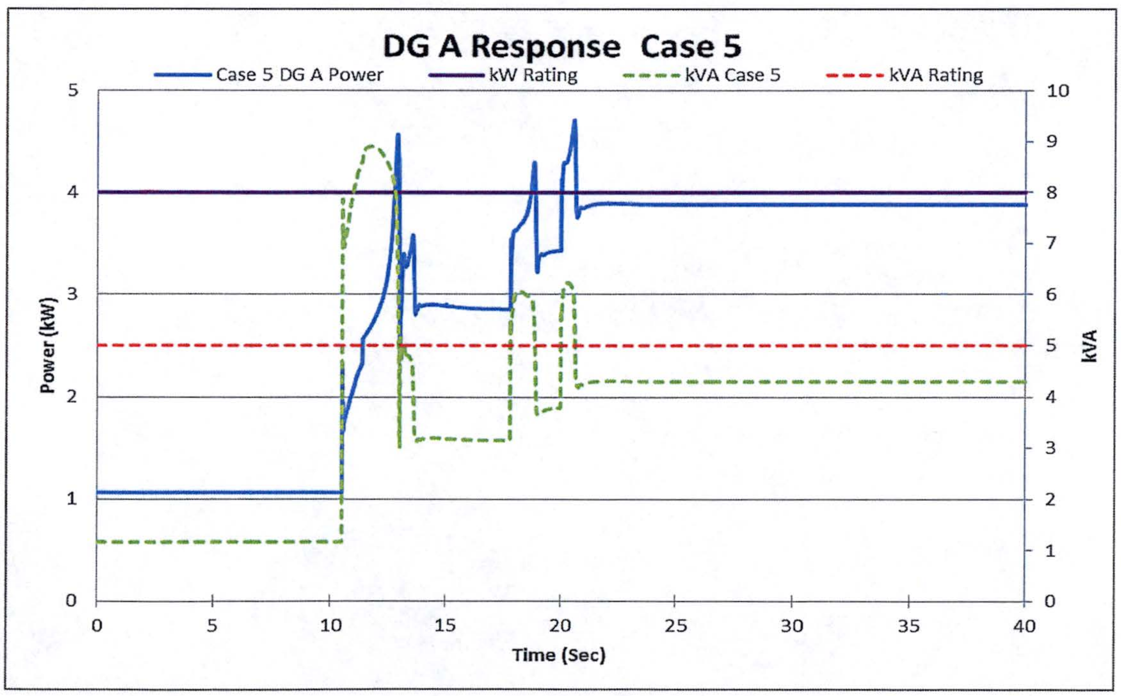

Figure 6: DG A Response - Case 5 kW and kVA

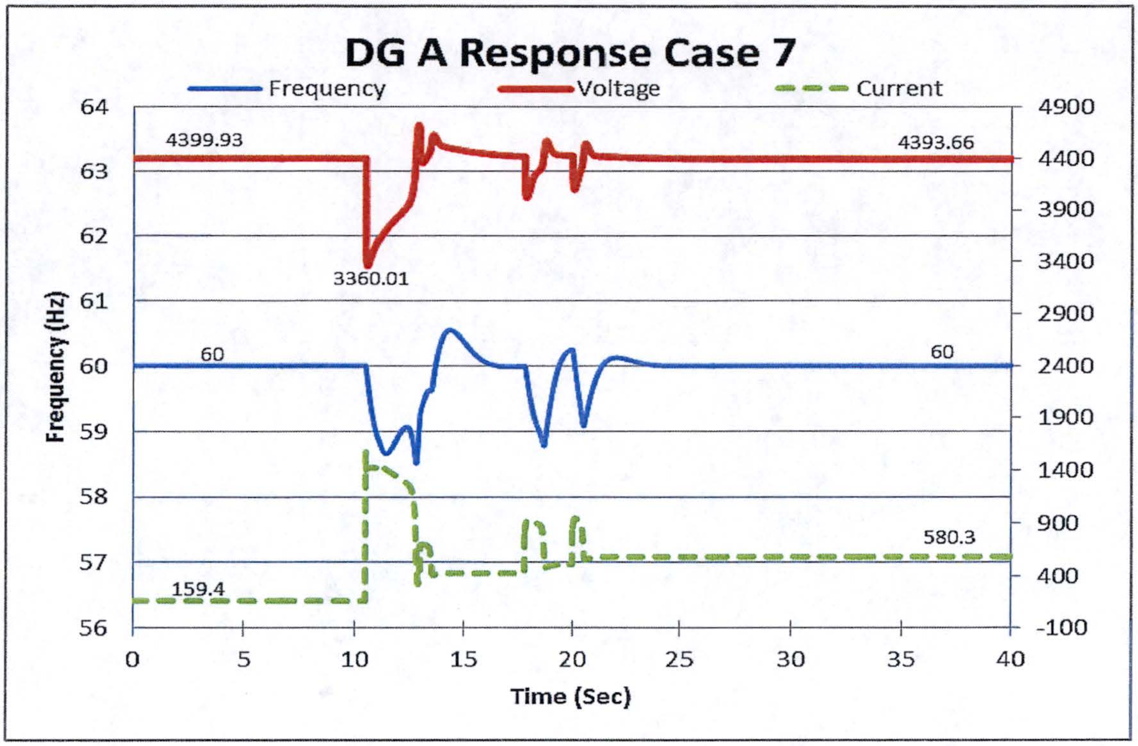

Figure 7: DG A Response Case 7 Voltage, Frequency, Current

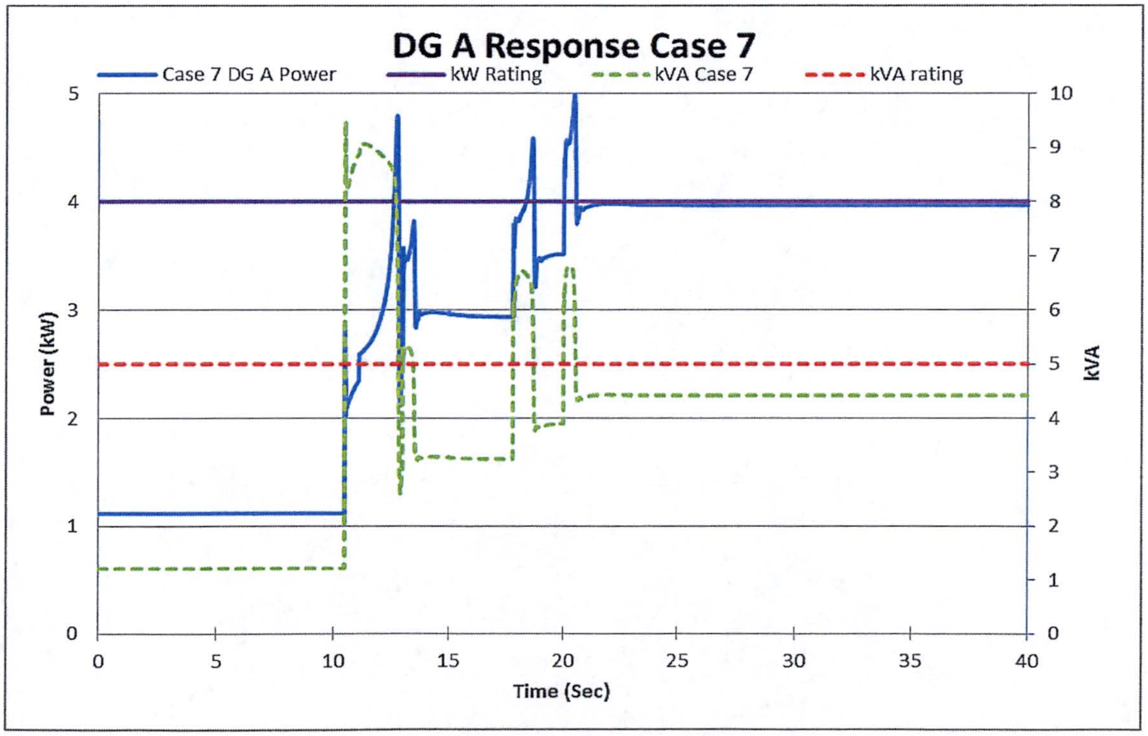

Figure 8: DG A Response - Case 7 kW and kVA

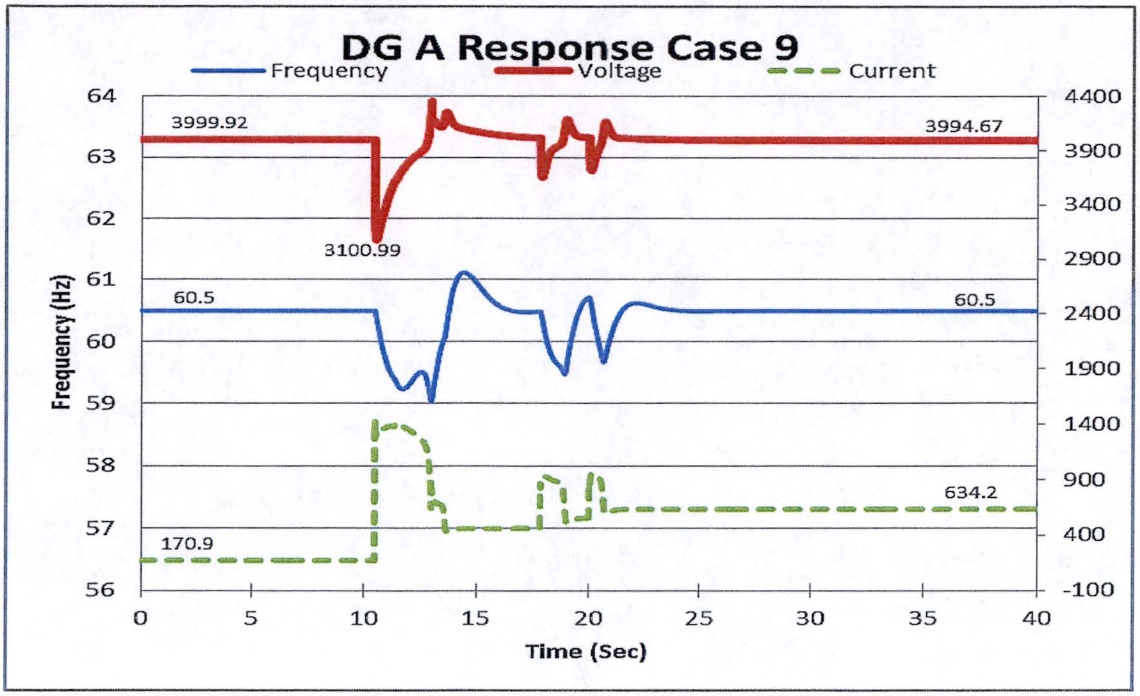

Figure 9: DG A Response Case 9 Voltage, Frequency, Current

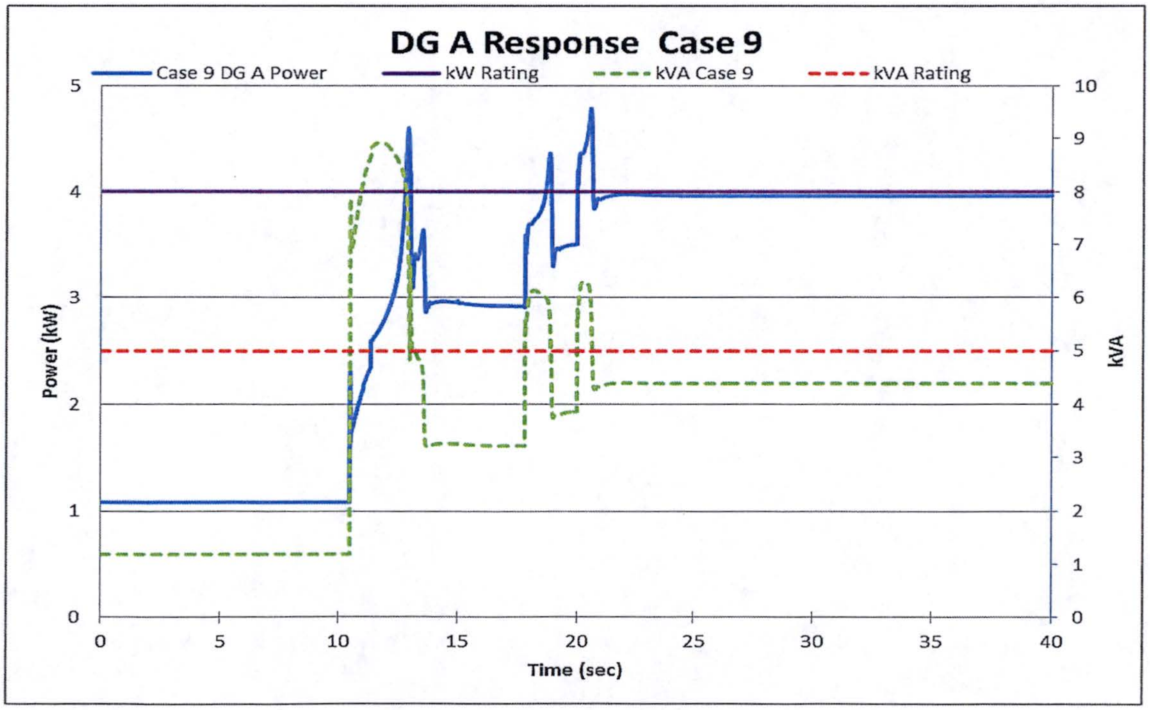

Figure 10: DG A Response - Case 9 kW and kVA

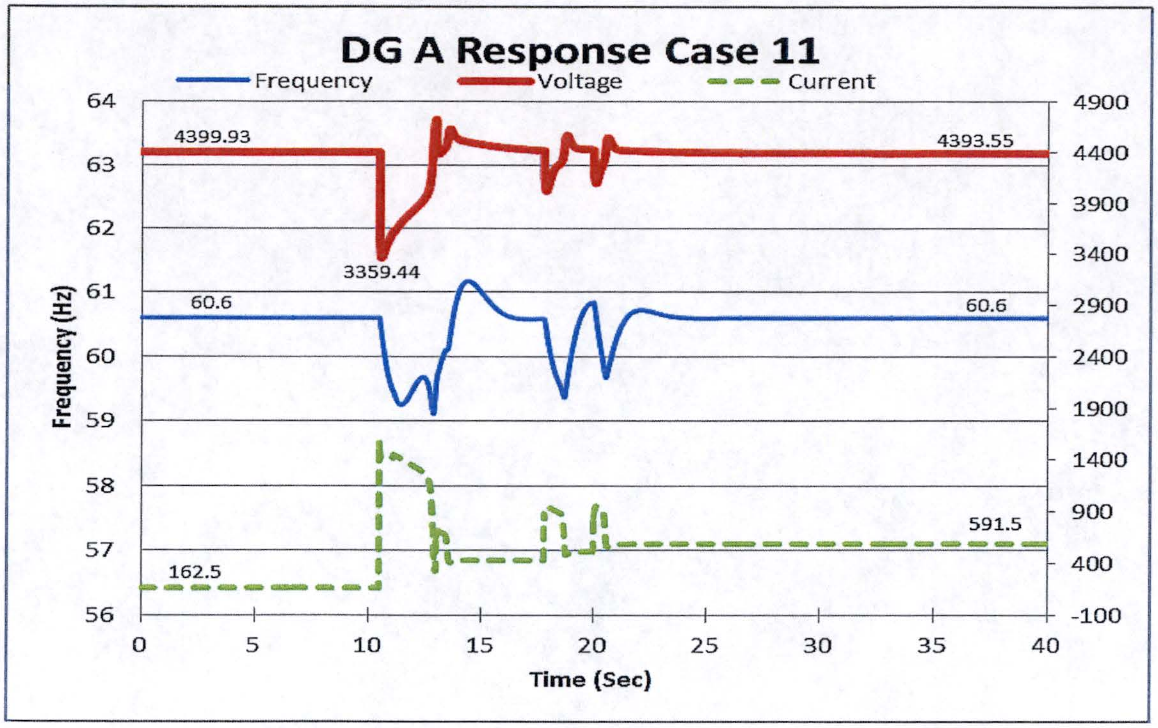

Figure 11: DG A Response Case 11 Voltage, Frequency, Current

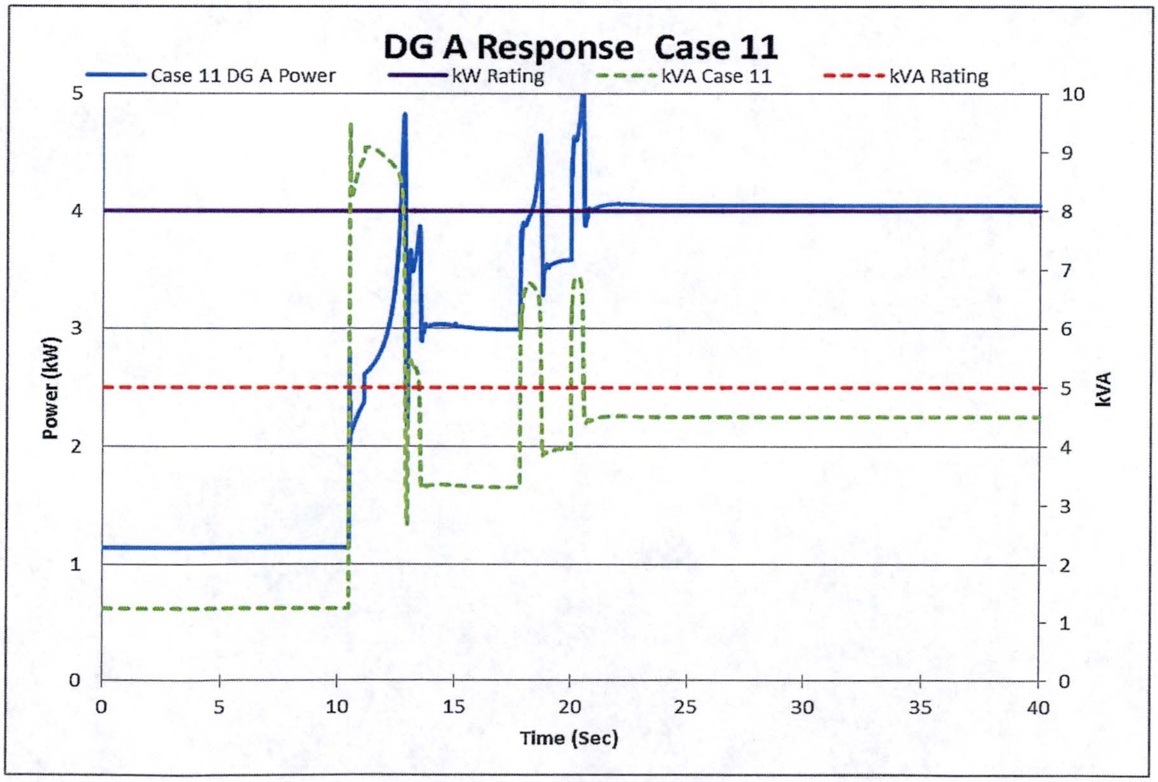

Figure 12: DG A Response - Case 11 kW and kVA

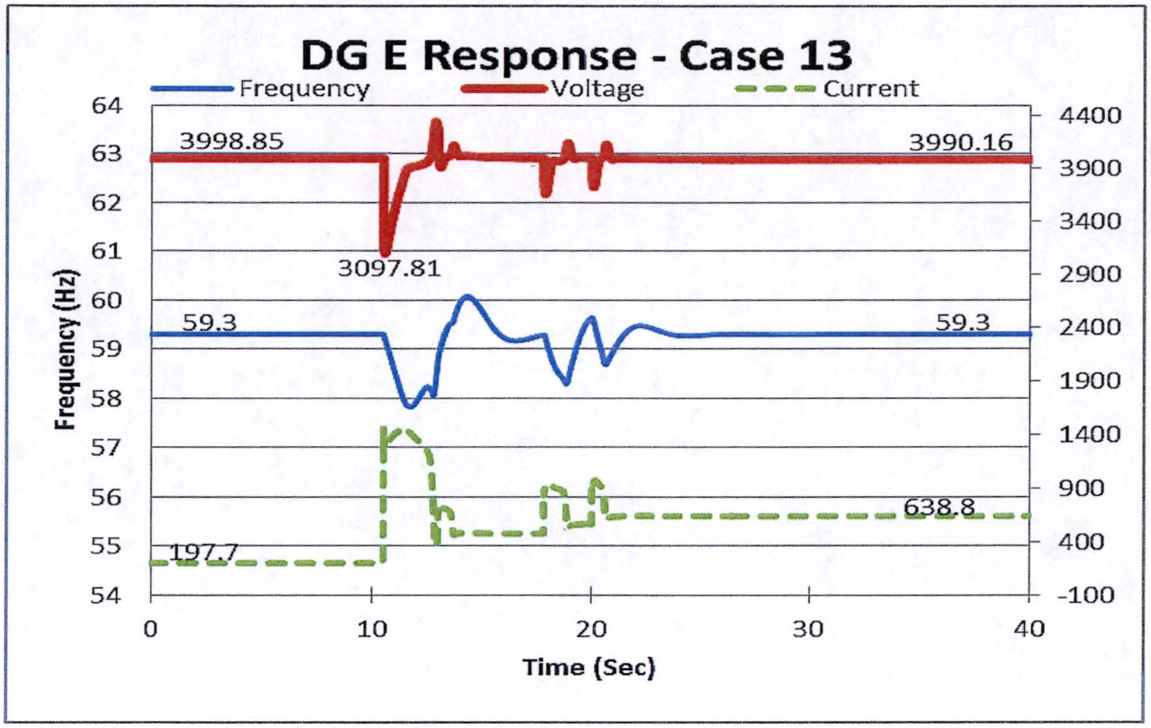

Figure 13: DG E Response Case 13 Voltage, Frequency, Current

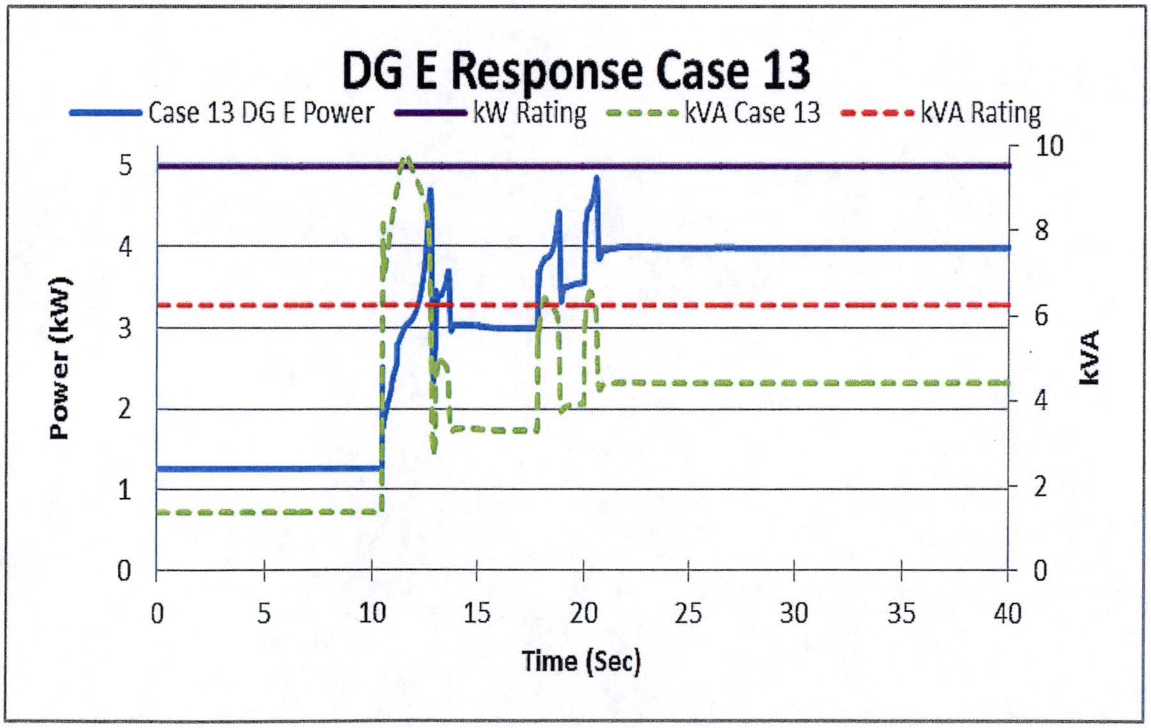

Figure 14: DG E Response - Case 13 kW and kVA

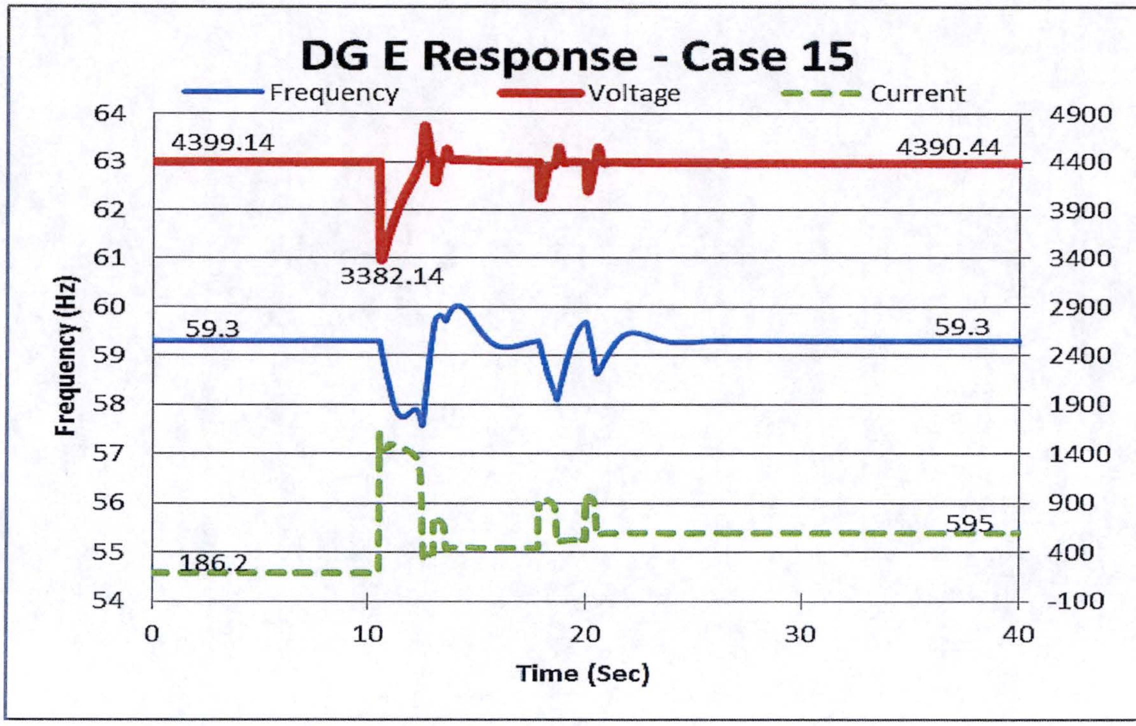

Figure 15: DG E Response Case 15 Voltage, Frequency, Current

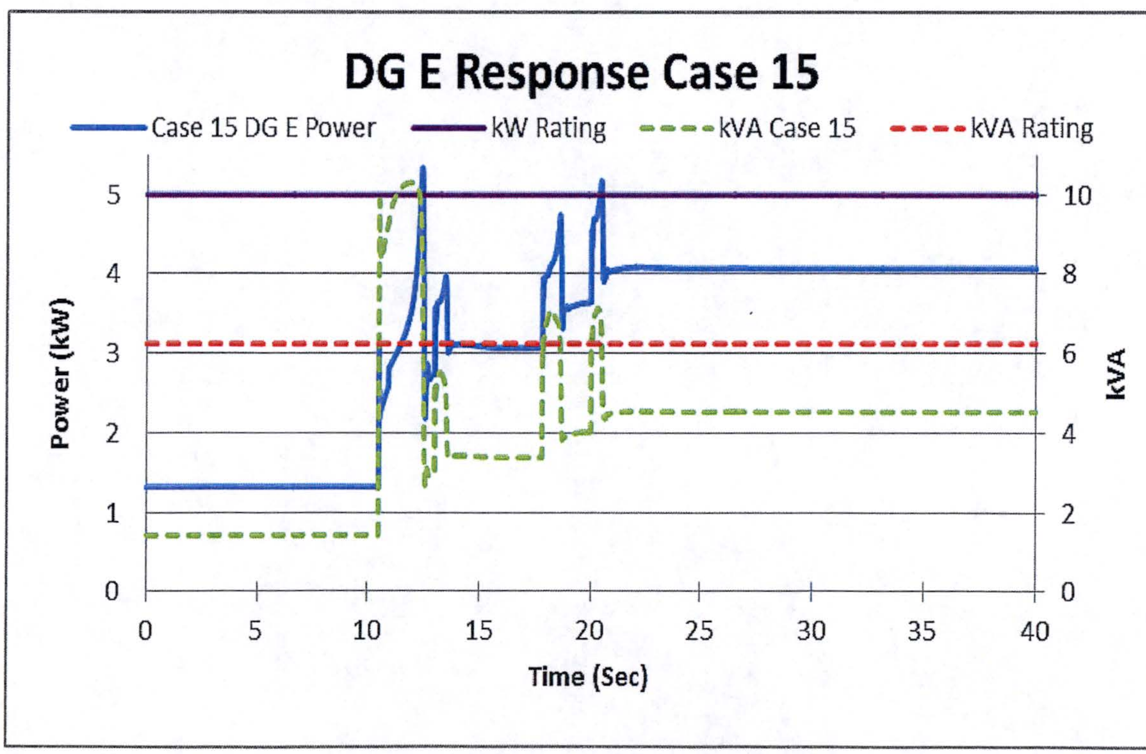

Figure 16: DG E Response - Case 15 kW and kVA

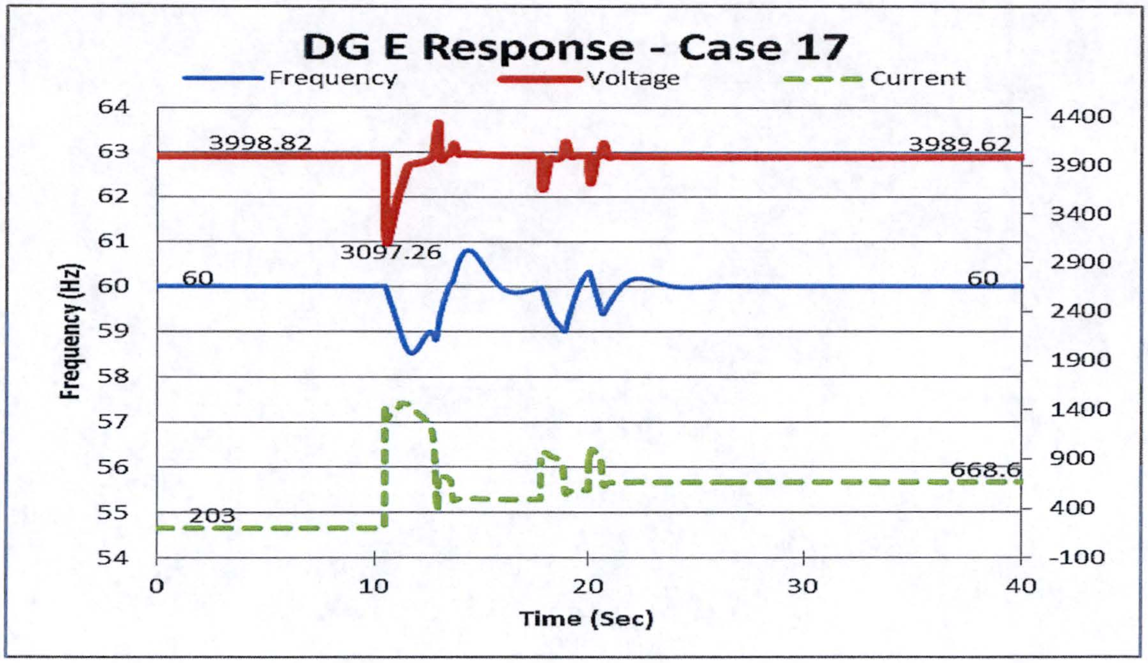

Figure 17: DG E Response Case 17 Voltage, Frequency, Current

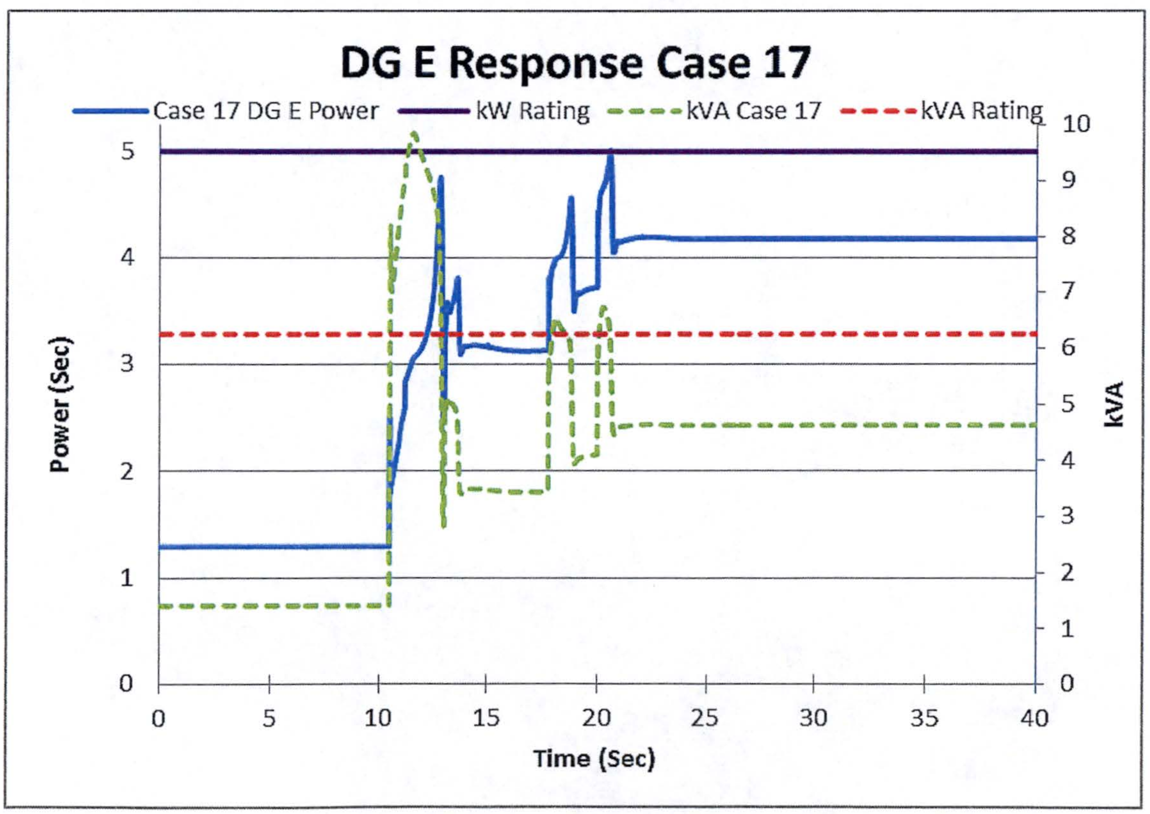

Figure 18: DG E Response - Case 17 kW and kVA

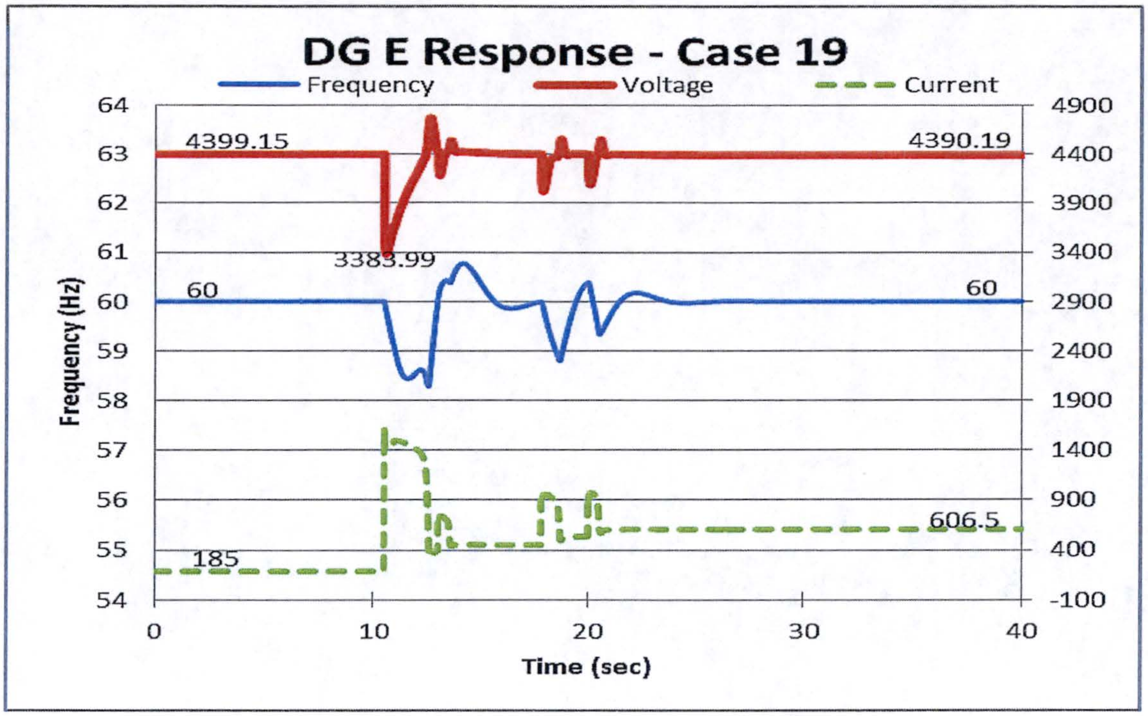

Figure 19: DG E Response Case 19 Voltage, Frequency, Current

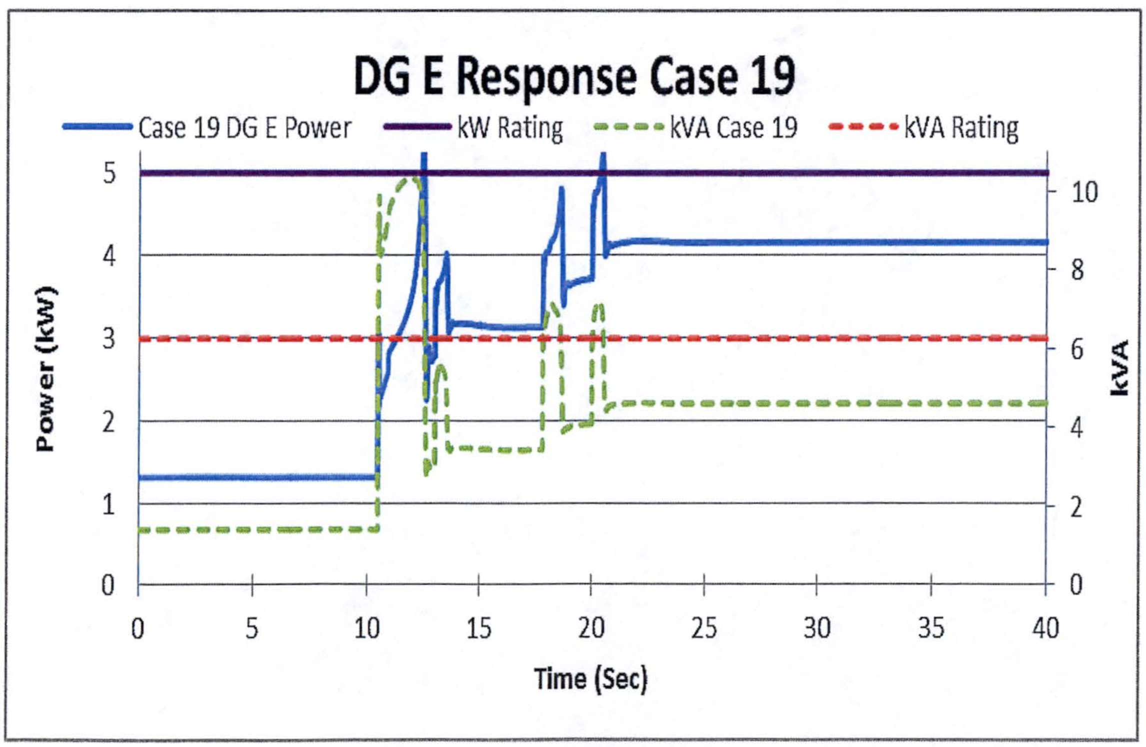

Figure 20: DG E Response - Case 19 kW and kVA

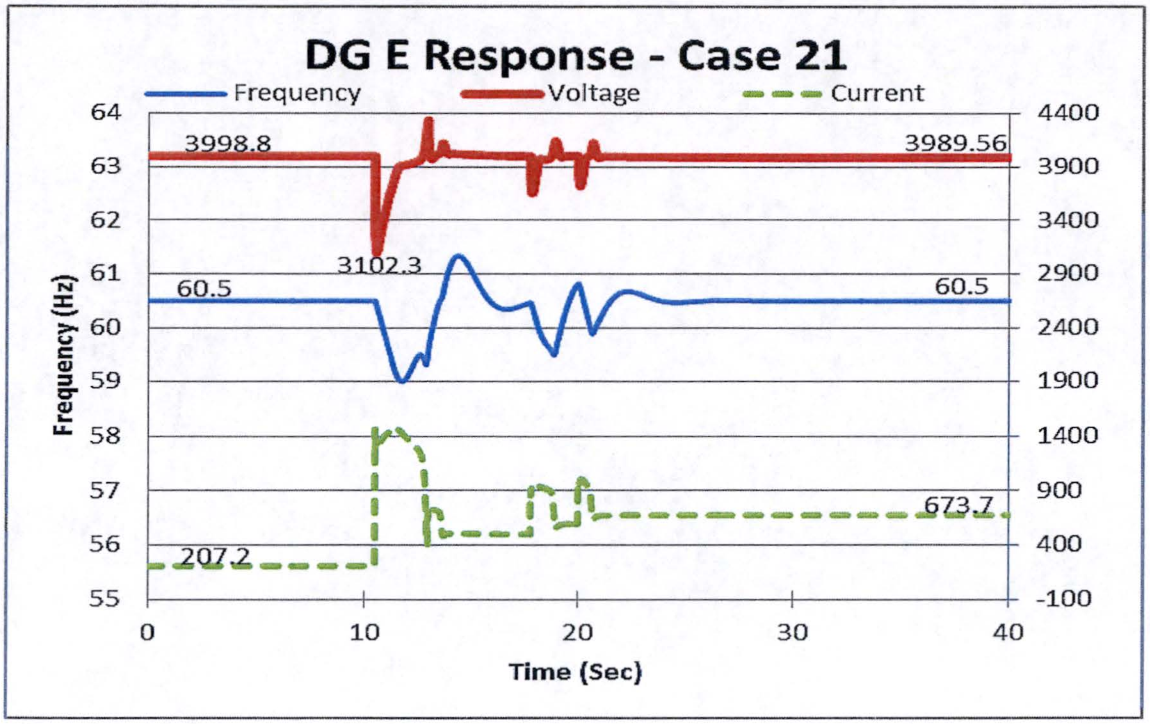

Figure 21: DG E Response Case 21 Voltage, Frequency, Current

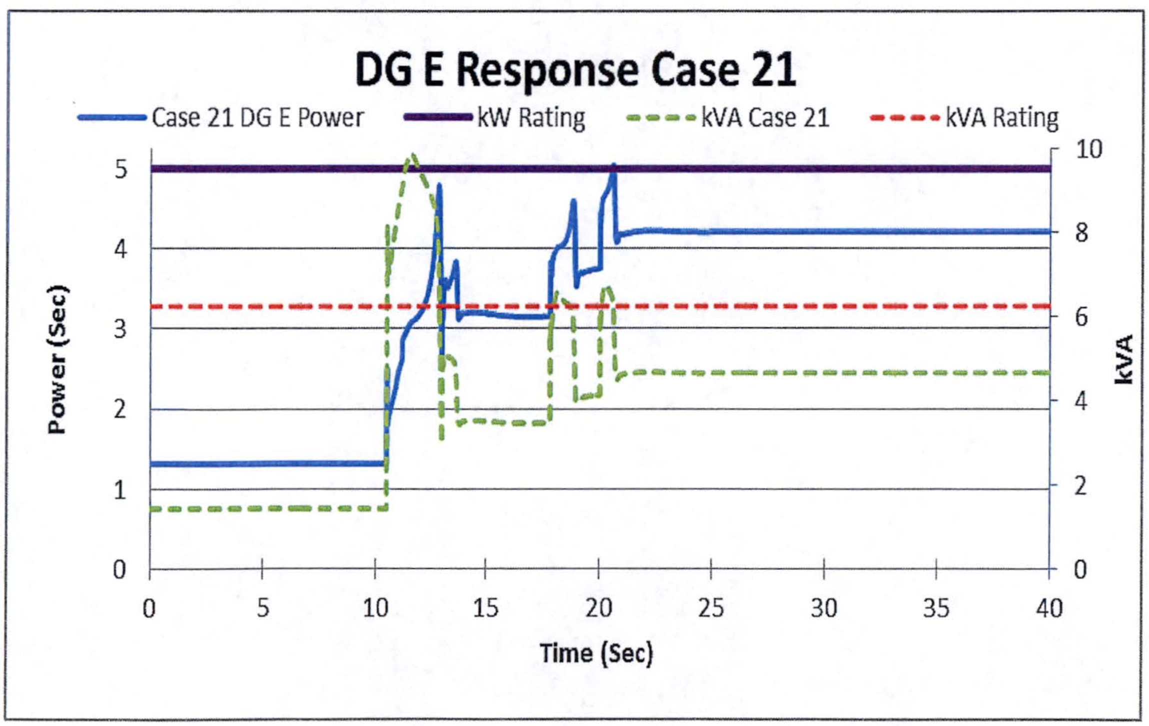

Figure 22: DG E Response - Case 21 kW and kVA

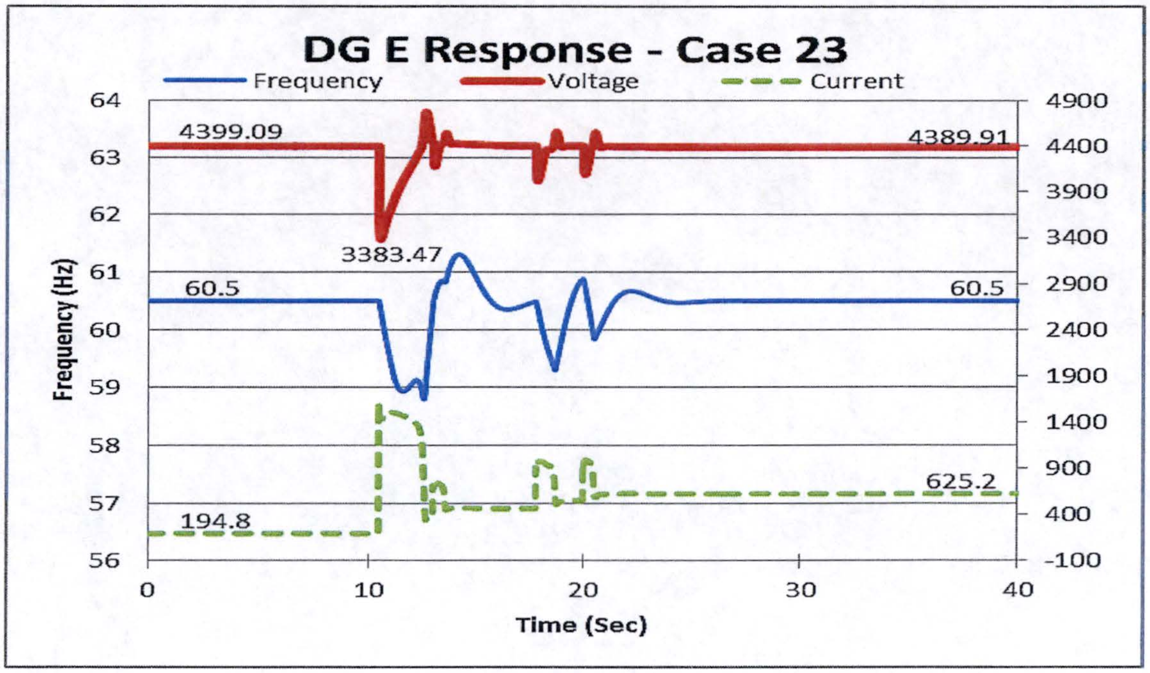

Figure 23: DG E Response Case 23 Voltage, Frequency, Current

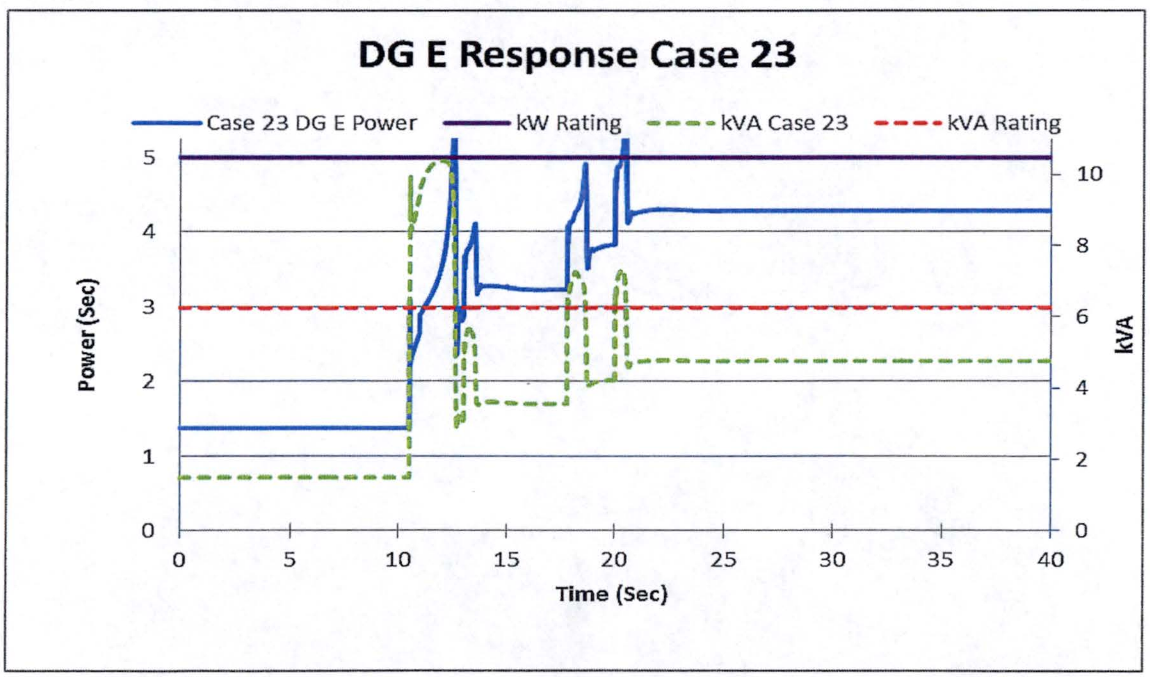

Figure 24: DG E Response - Case 23 kW and kVA

Exhibit 8: DG A and E Dynamic Response Plots

Exhibit 9: Description of Methodology Used in Deriving Table 4

Inputs:

Loads	Frequency (Hz)			Voltage (V)				Rated Speed		
	f_{Rated}	f_{Min}	f_{Max}	V_{Rated}	V_{Min1}	V_{Nom}	V_{Max}	S_1 (rpm)	S_{synch}	# Poles
Reactor Core Spray Pumps	60	59.3	60.5	4000	3793	4160	4400	1780	1800	4
RHR Pumps	60	59.3	60.5	4000	3793	4160	4400	1185	1200	6
RHR Service Water Pumps	60	59.3	60.5	4000	3793	4160	4400	1180	1200	6
Emergency Service Water Pumps	60	59.3	60.5	4000	3793	4160	4400	1775	1800	4

NOTE: Vrated is also equal to the new proposed DG minimum steady state voltage (i.e. 4000V)
VMin1 predicts DG A loading under previous acceptable minimum steady state voltage of 3793V

	Motor Loads			Static Load	
	BHP	kW	kVAR	kW	kVAR
CS	691	552	268.1	-	-
RHR	1798	1429	659.6	-	-
RHRSW	574	463	256.9	-	-
ESW	440	357	196.1	-	-
U1 Lump	-	718.8	348.1	252.6	0
U2 Lump	-	75.5	36.6	75.0	0
DGE Lump	-	135	65.4	103.5	0

	Motor Loads			Static Load	
	BHP	kW	kVAR	kW	kVAR
CS	691	552	268.1		
RHR	1798	1429	659.6		
RHRSW	574	463	256.9		
ESW	440	357	196.1		
U1 Lump*	-	350	169.5	156.55	
U2 ESF Loads Lumped (FSD)	-	75.5	36.6	75.0	
DGE Lump	-	135	65.4	103.5	

* U1 Lump = (Total ESF & Other Non-ESF Loads) - Unit 2 ESF Loads Lumped (FSD)

NOTE: The BHP and KVAR values above for the major motors (RHR, CS, RHRSW & ESW) where generated in ETAP while ensuring the kW values were kept equal to those in FSAR Table 8.3-3.

1- The change in speed (rpm) for the 4 major motor loads (RHR, CS, RHRSW and ESW) started during the DBA event analyzed was calculated per Equation [3].

2- The resulting speed defined as S2 = S1 - ΔS was then calculated first in rpm and then in percentage as a function of the rated speed [(S2/S1) = 1- (ΔS/S1)]

3- The calculated resulting speed percentage calculated in step 2 was cubed to estimate the resulting HP and kW of the motor loads using data in Table 1. The following Affinity Laws equation was used to adjust motor HP and kW from their rated values: HP2 = (f2/f1)^3*HP1.

NOTE: The loading values in Table 1 are assumed to correspond to 4000V and 60Hz. This assumption is validated by the following derivation of RHR and Core Spray loading values that match those in the FSAR Table 8.3-3 Rev.57:

<u>**RHR Pump**</u>

Pump Maximum Brake Horsepower (BHP_{Max}) at any head and flow = 1800 HP[16]

Motor kVA = [(.746/HP).(1800HP)]/[($PF_{@Full\ Load}$).($Eff_{@Full\ Load}$)[17] = 1570 kVA

Motor kW = kVA x ($PF_{@Full\ Load}$) = **1429 kW**

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[16] Ref: Spec#21A9369AZ Rev.2 Sh.5

[17] Ref: FF124510 Sh.1201 rev.6

Core Spray Pump:

Pump Maximum Brake Horsepower (BHP_{Max}) at any head and flow = 690 HP[18]

Motor kVA = [(.746/HP).(690HP)]/[($PF_{@Full\ Load}$).($Eff_{@Full\ Load}$)[19] = 613 kVA

Motor kW = kVA x ($PF_{@Full\ Load}$) = **552 kW**

4- The remaining minor loading values grouped per Table 1Table 1 were adjusted for frequency and voltage variations by applying the average percent variation adjustment for the four major motor loads in Table 11 at corresponding voltages and frequencies.

5- Non-motor loads (static loads for Unit 1, Unit2 and DG-E) are adjusted for voltage variations based on constant Z model using the following : $\boldsymbol{P_2} = \left(\boldsymbol{P_1 x}\left(\frac{V_2}{V_1}\right)^2\right)$

		V_Rated		V_min		V_Nom		V_Max	
		kW	kVAR	kW	kVAR	kW	kVAR	kW	kVAR
U1 Lumped Static Loads		252.55	[redacted]	227.09	[redacted]	273.16	[redacted]	305.59	[redacted]
U2 Lumped Static Loads		75.00	[redacted]	67.44	[redacted]	81.12	[redacted]	90.75	[redacted]
DGE Lumped Static Loads		103.50	[redacted]	93.06	[redacted]	111.95	[redacted]	125.24	[redacted]

Table: Static Load Adjustment when All Loads (ESF and Non-ESF) per FSAR Table 8.3-3 Considered.

		V_Rated		V_min		V_Nom		V_Max	
		kW	kVAR	kW	kVAR	kW	kVAR	kW	kVAR
U1 Lumped Static Loads		156.55	[redacted]	140.77	[redacted]	169.32	[redacted]	189.43	[redacted]
U2 Lumped Static Loads		75.00	[redacted]	67.44	[redacted]	81.12	[redacted]	90.75	[redacted]
DGE Lumped Static Loads		103.50	[redacted]	93.06	[redacted]	111.95	[redacted]	125.24	[redacted]

Table: Static Load Adjustment when Manually Initiated Non-ESF Loads are Not Considered

6- The adjusted load values for all the aforementioned loads are then summed to produce Table 4.

[18] Ref: Spec#21A9369AY Rev.2 Sh.5
[19] Ref: FF126510 Sh.801 Rev.6

Exhibit 10: Development of RHRSW CKT Model Parameters for ETAP Transient Modeling

The calculation below uses the method presented by MPR in Reference 6.4.6 to calculate the ETAP CKT model parameters for the RHR-SW motor equivalent circuit. The program used is Maplesoft.

INPUTS:

PARAMETERS	UNITS	RHRSW PUMP MOTOR	
		VALUE	**REF.**
Rated Voltage (V_{base})	kV	4	FF103120 Sh.401
Horsepower	HP	600	FF103120 Sh.401
Full Load Efficiency	%	92.5	FF103120 Sh.401
Full Load Power Factor	%	88	FF103120 Sh.401
Locked Rotor Power Factor	%	25	FF103120 Sh.401
Locked Rotor Stator Current ($I_{s,lr}$)	pu	6.4	FF103120 Sh.401
Full Load Slip (S_{fl})		0.0167	FF103120 Sh.401 & Calculated
Locked Rotor Torque (T_{lr})	pu	1	FF103120 Sh.401
Rotor magnetic leakage cage factor (K_x)		-0.45	FF103120 Sh.401

The resultant parameter values are:

Rs = 1.206
Xs = 6.029 rounded to 6.030
Xm = 301.5

Xrfl = 12.059
Rrfl = 1.847

Xrlr = 1.5 * Xs = 9.045
Rrlr = 2.686

The ETAP dynamic model also requires a load-speed curve. Load torque versus speed information was not available for RHRSW pump. The estimated RHR pump curve per EC-024-1029 was used for RHRSW. This is a reasonable approximation, since these two are centrifugal pumps which typically have similar per unit load characteristics. As such, the following load-speed curve characteristics were used for RHRSW:

RHRSW LOAD TORQUE CURVE

% Speed	% Slip	% Torque
0	100	11.7
5	95	8.5
10	90	6.4
15	85	5.4
20	80	5.4
25	75	6.3
30	70	8
35	65	10.6
40	60	13.9
45	55	18
50	50	22.7
55	45	27.9
60	40	33.8
65	35	40.1
70	30	46.8
75	25	53.9
80	20	61.4
85	15	69.1
90	10	77
95	5	85
100	0	93.2

restart

RHR SW Pump Motor

$s_{fl} := \frac{20}{1200}$

$$\frac{1}{60} \qquad (2.1)$$

$\tau_{fl} := 1$

$$1 \qquad (2.2)$$

$\tau_{lr} := 1$

$$1 \qquad (2.3)$$

$i_{r\_fl} := .95$

$$0.95 \qquad (2.4)$$

$i_{s\_lr} := \frac{510}{79.4}$

$$6.423173804 \qquad (2.5)$$

$i_{r\_lr} := .95 \cdot i_{s\_lr}$

$$6.102015114 \qquad (2.6)$$

$p := \frac{2}{3}$

$$\frac{2}{3} \qquad (2.7)$$

$assume(0 < R_r)$

$PF_{lr} := .25$

$$0.25 \quad (2.8)$$

$K_x := -.25$

$$-0.25 \quad (2.9)$$

$R_{r\_fl} := evalf\left(\frac{s_{fl} \cdot \tau_{fl}}{i_{r\_fl}^2}\right)$

$$0.01846722069 \quad (2.10)$$

$R_{r\_lr} := \frac{\tau_{lr}}{i_{r\_lr}^2}$

$$0.02685674910 \quad (2.11)$$

$K_r := \frac{R_{r\_lr}}{R_{r\_fl}} - 1$

$$0.454292963 \quad (2.12)$$

$X_{rlr} := \frac{X_{s\_lr}}{p}$

$$\frac{3}{2} X_{s\_lr} \quad (2.13)$$

$R_s := \frac{(X_{s\_lr} + X_{rlr})}{\tan(\cos^{-1}(PF_{lr}))} - R_{r\_lr}$

$solve\left(\frac{\sqrt{\left(\frac{1}{i_{s\_lr}^2} - (R_s + R_{r\_lr})^2\right)}}{1 + \frac{1}{p}} = X_{s\_lr}\right)$

$$0.06029703485 \quad (2.14)$$

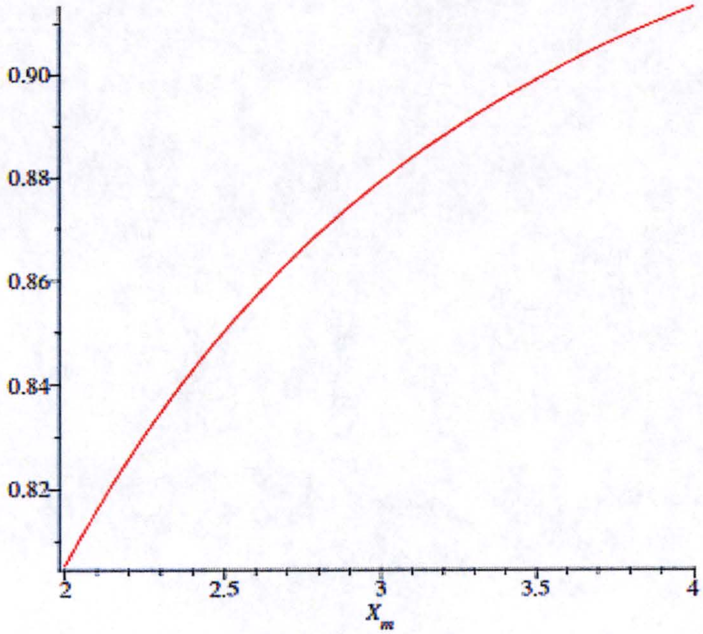
$X_{s\_lr} := \%$

$$0.06029703485 \quad (2.15)$$

$$0.6454972234\, X_{s\_lr} - 0.02685674910 \quad (2.16)$$

$X_s := X_{s\_lr}$

$$0.06029703485 \quad (2.17)$$



for X_m **from** 3.015 **to** 3.016 **by** .0001 **do** PF_{fc}; $print(X_m)$ **od**

0.8799958990
3.015
0.8800005822
3.0151
0.8800052657
3.0152
0.8800099487
3.0153
0.8800146309
3.0154
0.8800193132
3.0155
0.8800239952
3.0156

0.8800286770
3.0157
0.8800333582
3.0158
0.8800380391
3.0159
0.8800427190
3.0160 **(2.21)**

$$X_{r\_ft} := \frac{X_{rlr}}{1 + K_x}$$

$$0.1205940697 \qquad \textbf{(2.18)}$$

$$Z_{eq} := R_s + I \cdot X_s + \frac{\left(-X_m \cdot X_{r\_ft} + \frac{\left(I \cdot X_m \cdot R_{r\_ft}\right)}{s_{ft}}\right)}{\frac{R_{r\_ft}}{s_{ft}} + I \cdot \left(X_m + X_{r\_ft}\right)}$$

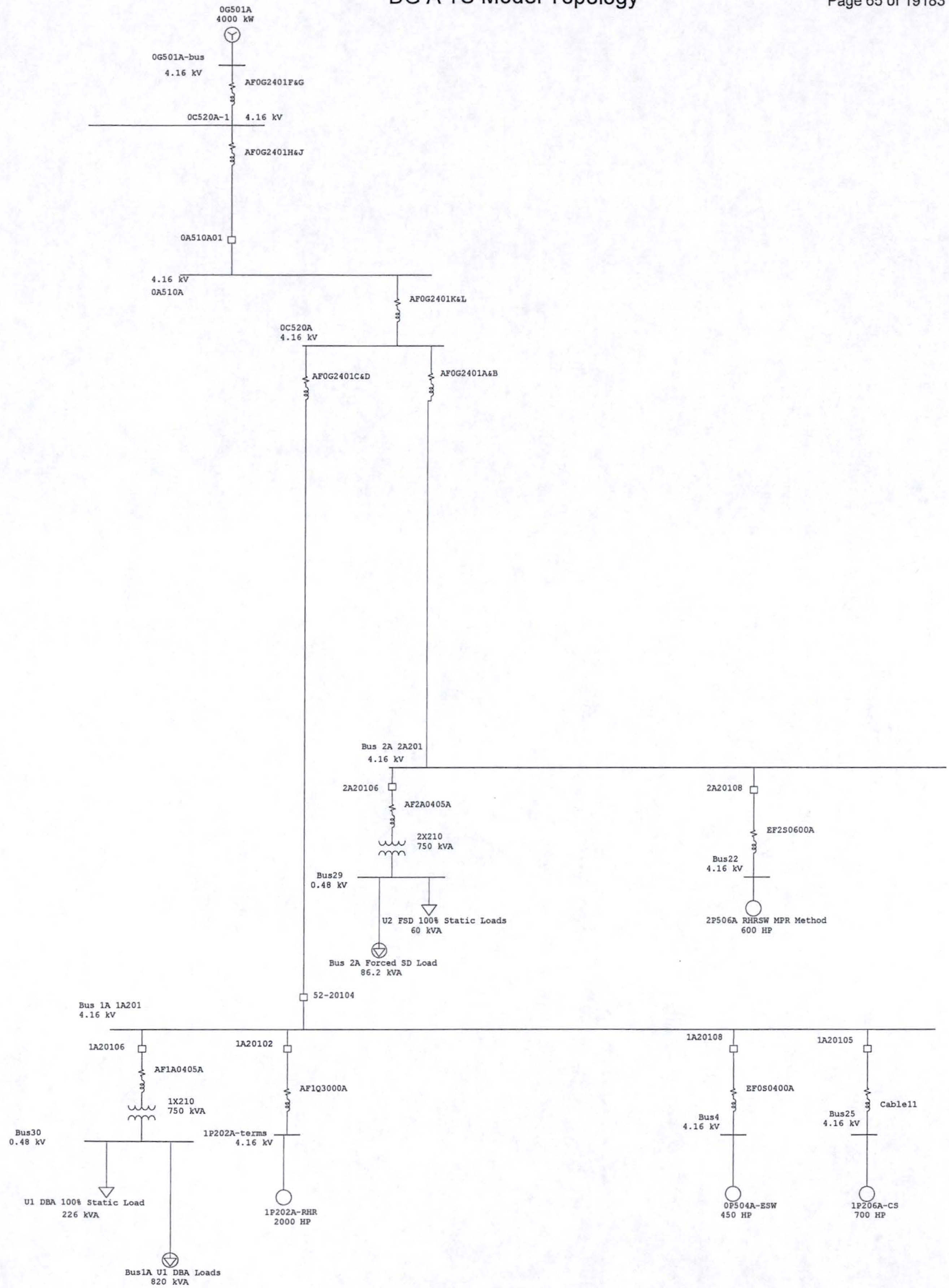
$$0.01206481947 + 0.06029703485\, I + \frac{-0.1205940697\, X_m + 1.108033241\, I X_m}{1.108033241 + I\,(X_m + 0.1205940697)} \qquad \textbf{(2.19)}$$

$$PF_{ft} := \frac{\mathrm{Re}(Z_{eq})}{\mathrm{abs}(Z_{eq})}$$

$$\frac{0.01206481947 + \Re\left(\frac{-0.1205940697\, X_m + 1.108033241\, I X_m}{1.108033241 + I\,(X_m + 0.1205940697)}\right)}{\left|0.01206481947 + 0.06029703485\, I + \frac{-0.1205940697\, X_m + 1.108033241\, I X_m}{1.108033241 + I\,(X_m + 0.1205940697)}\right|} \qquad \textbf{(2.20)}$$

$$plot(PF_{ft}, X_m = 2..4)$$

Attachment 9.1
DG A TS Model Topology



Attachment 9.2
DG E TS Model Topology