NEXTera ENERGY SEABROOK

September 22, 2009
SBK-L-09206
Docket No. 50-443

U. S. Nuclear Regulatory Commission
Attention: Mr. Art Burritt, Chief Branch 3
475 Allendale Ave.
King of Prussia PA 19406-1415

Seabrook Station
Regulatory Conference Information

On August 28, 2009, the NRC issued inspection report 05000443/2009007 informing NextEra Energy Seabrook, LLC (NextEra) of a preliminary white finding. The finding is associated with a failure to establish adequate design control measures to modify a cooling water flange that led to a failure of emergency diesel generator-B in February 2009. In response to the inspection report, NextEra submitted a letter on September 2, 2009 stating our intention to attend a regulatory conference to discuss the preliminary finding.

During a telephone call on September 11, 2009, the NRC staff provided NextEra with questions related to the significance of the event. Attachment 1 contains responses to the questions.

Attachment 2 contains NextEra's presentation for the regulatory conference on September 30, 2009. This is a preliminary version of the presentation, which may change during final preparations for the conference.

If you have any questions regarding this information, please contact Mr. Michael O'Keefe, Licensing Manager, at (603) 773-7745.

Sincerely,

NextEra Energy Seabrook, LLC

Gene St. Pierre

Gene St. Pierre
Vice President North

Attachments:

1. Responses to NRC Questions
2. Preliminary Presentation for Regulatory Conference

cc: S. J. Collins, NRC Region I Administrator
D. L. Egan, NRC Project Manager
W. J. Raymond, NRC Resident Inspector
Document Control Desk

Attachment 1

Responses to NRC Questions

1. In an early letter from Cummins, the vendor did not support the conclusions of your Electrical Analysis. What was the basis for Cummins to revise the letter sent to you in response to your July 28, 2009 letter? Provide any additional vendor documentation to support the 1-of-2 SEPS success criteria.

Response: The vendor letter was received on 08/04/09 and was based on a qualitative analysis. After the vendor was requested to provide the response of the genset under overloaded conditions factory testing results were provided by Cummins on 08/28/09. These test results indicated a different behavior that showed improved genset response. See Figure 1.

Response Preparer:	Kenneth J. Letourneau K J Letourneau	Date: 09-22-09
Response Verifier:	Randy C. Jamison R. Jamison	Date: 9-22-09

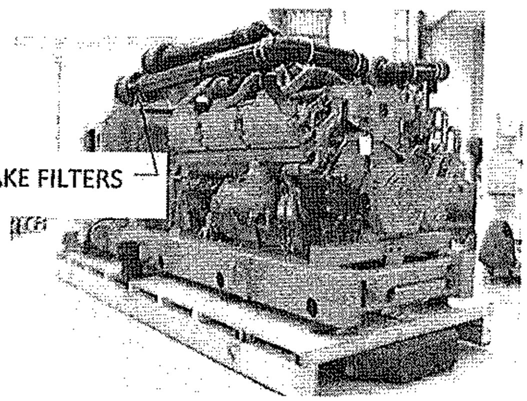
2. The Engineering Evaluation (Rev 2) page 9 credits additional SEPS power based on break-in. How were potential derating factors - such as fuel density/energy/restrictions and air restrictions identified in Cummins letter – dealt with?

***Response:** If the on-site fuel density is higher than the fuel used during factory testing an increase in power of 1% can be expected. Conversely, if the on-site fuel density is less then a decrease in power can be expected. The factory fuel density is equivalent to the fuel density of the SEPS procured fuel and no reduction or increase in power output is needed.*

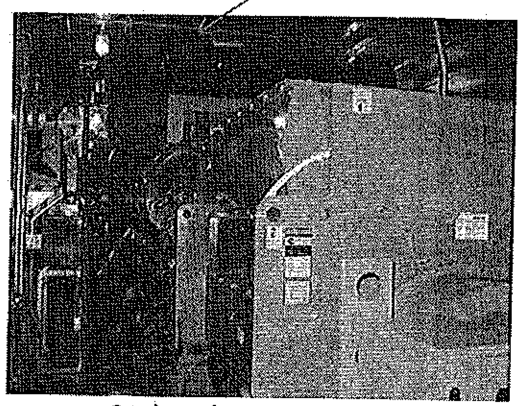
If the air flow during factory testing was greater than the air flow for the as installed gensets then a reduction in power output would be expected. Conversely, if the air flow during factory testing was restricted more than the air flow for the as installed gensets an increase in power output would be expected. The gensets used the same air filters during testing as the installed units. At the factory test the test cell air intake used building air as the supply. The as installed gensets have a more direct outdoor air supply. Although the as installed gensets have a more direct supply of outdoor air the evaluation considers the air intake to be equivalent and a power reduction or increase does not need to be used.

AIR INTAKE FILTERS

AIR INTAKE FILTERS



Factory Test Facility



Seabrook Station Installation

Response Preparer:	Kenneth J. Letourneau K J Letourneau	Date: 09-22-09
Response Verifier:	Gregg F. Sessler [signature]	Date: 9/22/09

3. **Part 1** - Explain the dynamic response of the SEPS governor to increase in load. Specifically address the ultimate fuel injection state (the equivalent to fuel rack position). How does the governor maintain a 4% frequency reduction at a 108% load? **Part 2** - If frequency is not reduced by 4%, would the SEPS genset trip on overload? **Part 3** - Is there a possibility that operators would take actions to maintain frequency at 60 hz causing the SEPS genset to trip on overload? **Part 4** - If the SEPS genset has never been operated above 100% rated engine output, how is the governor response determined? Provide supporting data.

Response:

Part 1 - The electronic control module (ECM) provides two different fuel pressures to the fuel injectors, Rail Pressure, and Timing Pressure. Only part of the fuel supplied to the injectors is actually used to fuel the engine. The balance is recirculated back to the fuel day tank.

The normal engine driven fuel pump pressure is 380 psia. This pressure is constant and not load dependent.

The rail pressure is the main fuel supply to injectors and the pressure varies with load. At ~1400 KW the pressure is 100 psia. At 2500 KW the pressure is 175 psia. The actuator valve that controls rail pressure is electronically controlled from a fuel card in the engine control panel (SEPS-CP-5/6).

The timing pressure adjusts injector fuel delivery timing as the name suggests. This pressure also varies with load. At ~1400 KW the pressure is 92 psia. At 2500 KW the pressure is 80 psia. The actuator valve that controls timing pressure is also electronically controlled from the fuel card in the engine control panel (SEPS-CP-5/6).

The fuel card interacts with the engine's electronic governor. The fuel card is programmed with limits on fuel delivery such that the rail pressure and timing pressure actuator valves will not continue to increase fuel pressure once those limits are reached. Beyond that point additional load changes will cause the genset to settle into a speed below the target 60 Hz. There is a fuel boost feature designed to handle step load changes and return the genset to target speed. Based on discussions with Cummins, the boost feature will provide extra fueling for a short period of time when speed drops by about 80 rpm. After the fuel boost times out, the engine will return to steady state fueling.

The steady state behavior of the genset would be analogous to a truck in a constant gear that has the fuel pedal fully depressed on a hill and the incline becomes steeper. The net result of the increased load would be a decrease forward speed. The truck does not stall as long as the hill does not become too steep.

Part 2 – If voltage and frequency are maintained at rated values, the overcurrent setpoint will not be reached since the 509 A current corresponding to the adjusted base load (2936 kW/4.16 kV x SQRT 3 x 0.8 = 509 amp) is less than the Ampsentry threshold setting of 511 A (see the

SEPS Generator Protection Evaluation section in Appendix A of the Engineering Evaluation). Also see response to question 12.

Part 3 - There's no procedural guidance to control SEPS frequency because this parameter is controlled automatically via a software setpoint. There is no capability for operator frequency adjustment.

Part 4 - Based on overload testing performed by Cummins on the QSK23 genset there were no anomalies identified with governor operation during operation above 100% rated engine output

Part 1

Response Preparer:	Greg F. Sessler	Date: 9/22/09
Response Verifier:	Richard R. Belanger	Date: 9-22-09

Part 2 & 4

Response Preparer:	Kenneth J. Letourneau K J Letourneau	Date: 09-22-09
Response Verifier:	Randy C. Jamison	Date: 9/22/09

Part 3

Response Preparer:	David F. Kelly	Date: 9/22/09
Response Verifier:	Kenneth J. Browne	Date: 9/22/09

4. Are all of the engine subsystems and support systems evaluated to handle the overload under the evaluated condition?

Response:

There are five SEPS genset mechanical subsystems:

Lube Oil
Engine Cooling
Fuel
Turbo Chargers
Exhaust

Lube Oil:

The main engine lube oil pump is engine driven. When the SEPS genset loading reaches the point where engine speed begins to decrease the lube oil pump speed will also start to decrease. The pump flow change will be approximately directly proportional to the speed change. A small change in lube oil flow will not cause engine components to lose lubrication or lose the ability to transfer heat to the oil. However, based on energy balance principles, there will be a small increase in metal temperatures throughout the engine. The engine cooling system is coupled to the lube oil system and the small temperature changes will be passed along to the cooling system.

The lube oil temperature change between 1400 KW and 2500 KW is about 25 °F. The operating temperature at 2500 KW in warm ambient temperature is 225 °F.

Based on this data the expected oil temperature at 2936 KW with warm ambient air temperature would be about 235 °F.

A speed reduction will have a linear affect on flow and therefore a linear affect on differential temperature. Therefore conservatively assuming a 150 °F differential temperature in the oil system a 4.2% change in speed would add another 7 °F to the oil temperature. This would be approximately 242 °F.

The engine lube oil shutdown is 260 °F.

Engine Cooling:

The engine cooling system is comprised of two cooling loops, each with its own engine driven coolant pump, radiator, and thermostatic control valves. One system is a low temperature loop primarily for turbo charger compressed air cooling and the other is the high temperature loop that cools the lube oil, engine block, and power packs (cylinder assemblies). A single large electric motor driven fan provides air flow through both radiators. The radiators are arranged *in series with the low temperature radiator upstream of the high temperature radiator in the fan air flow path.*

The two thermostatic control units modulate cooling flow in their respective cooling loops.

The normal cooling temperature at 2500 KW is 190 °F for the high temperature loop and this does not vary significantly with ambient air temperature. The temperature change from 1400 KW to 2500 KW is only 10 °F primarily due to the ability of the thermostatic control valves to adjust flow through the engine. The change from 2500 KW to 2936 would therefore be only about 4 °F. Since we know that factory acceptance testing did not challenge the cooling system, but we have not observed the behavior of the system above factory test loads lets triple this number to 12 °F. Since the fans and pumps obey affinity laws a correction to differential temperature must also be applied. Using a similar conservative differential temperature of 102 °F the change in temperature would be 2 times 5 °F or 10 °F.

Therefore the final coolant temperature at 2936 KW would be about 212 °F.

The engine high coolant temperature shutdown is 220 °F.

The low temperature cooling loop does not have an engine shutdown feature.

Fuel:

The fuel system has significant excess flow capacity. Both pumps are engine drive. The only consequence to a slightly lower engine speed would be slightly lower recirculated fuel.
The behavior of the ECM unit as speed drops at increased loading was demonstrated by the Cummins test on a similar engine.

Turbo Chargers:

The turbo chargers are powered by exhaust flow which is a function of engine power, therefore there should not be a significant effect on turbo charger performance.

Exhaust:

The exhaust stacks are very large and there would be a negligible effect based on flow rates at higher engine loads.

Electrical Subsystems

The SEPS genset electrical subsystems consist of the PCC-3200 control cabinet, fuel priming pump, starters and genset sensors. The PCC-3200 provides monitoring, metering, and control. The control provides an operator interface to the genset, digital voltage regulation, digital governing, generator set protection and automatic paralleling functions. The control power is derived from the genset starting batteries. The voltage operating range is 8 VDC to 35 VDC.

The starting batteries are charged by an engine driven alternator and 120 VAC battery charger. A slight reduction in engine speed will also cause a slight reduction in alternator speed. This slight speed reduction will have a minimal affect on alternator output. The 120 VAC charger has an operating range of +/- 10%. The 120 VAC supply is provided through a 480/120 VAC transformer. The calculated voltage at the 480 VAC supply is 444 VAC. Using the +/- 10% range for the charger the minimum voltage at the 480 VAC supply would need to be 432 VAC. Based on this assessment the PCC-3200 would receive adequate voltage to perform the required functions and all genset sensors would provide the required signals. The fuel priming pump and starters are no longer required after the genset has started.

Mechanical Subsystems

Response Preparer:	Gregg F. Sessler	Date: 9/22/09
Response Verifier:	Richard R. Belanger	Date: 9-22-09

Electrical Subsystems

Response Preparer:	Kenneth J. Letourneau K.J. Letourneau	Date: 09-22-09
Response Verifier:	Randy C. Jamison	Date: 9-22-09

5. At the calculated 4% frequency decrease, how is the stability of the machine assured? At this elevated load, would the control system be capable of responding to changes in load? For example, if a pump were tripped off, would the engine overspeed?

***Response:** When load is applied to the generator, the genset / engine speed drops. As speed falls, the engine speed governor increases fueling, the shaft torque drives the engine / generator back toward the rated speed / frequency. When the torque from the applied load "through the generator" is less than the shaft torque supplied by the increased fueling, then the engine and genset accelerate back to the rated speed, and "settle in" at the rated speed.*

When > 100% load is applied, the behavior is the same, except the unit would "settle in" below the rated speed. This would be where the applied load (now lower actual load due to the lower steady state speed) "through the generator" equals the net shaft power of the engine. The engine speed governor will drive the engine to maximum fueling and power at the equilibrium speed.

When a large load is cycled off the engine speed governor will temporarily deliver reduced fueling and the decrease in net torque will decelerate the genset toward the rated speed. Prototype tests showed that on a Full Load Rejection the following results were obtained:

Voltage Rise: 15.7 %
Recovery Time: 2.5 Second
Frequency Rise: 4.3 %
Recovery Time: 1.1 Second

Although the genset would be operating at a higher load than tested the governor would be capable of responding for a load less than the full load rejection.

Response Preparer:	Kenneth J. Letourneau *K J Letourneau*	Date: 09-22-09
Response Verifier:	Randy C. Jamison *[signature] for R. Jamison*	Date: 9-22-09

6. In reference to ANSI C50.41-2000, American National Standard for "Poli - phase Induction Motors," how do you meet the requirements of Section 13.1, specifically section C.

Response: Section 13.1 permits induction motor operation at rated load with variations of (a) +/-10% voltage with rated frequency, (b) +/-5% frequency with rated voltage, and (c) combined voltage and frequency of 10% provided frequency is within +/-5% of rated. These are the same limits as provided in NEMA Standard MG-1, Section 12.44.1 to which Seabrook's motor were purchased (ref. specification 128-1).

The frequency reduction with one SEPS genset supplying the LOOP load is 4.2%, which is within the +/-5% allowance.

Attachment C provides terminal voltages for various loads when supplied by one SEPS genset. The maximum voltage reduction at the terminals for all motors is 9.4% which is within the +10% allowance.

For the 4000 V motors, the maximum voltage reduction at the motor terminals is 4.2% which when combined with the 4.2% frequency reduction results in 8.4% which is within the 10% combined allowance. About half of the 460 V motors required for safe shutdown meet the 10% combined criteria. The other half exceed the 10% criteria with the worst case being a voltage reduction at the motor terminals of 9.6% which when combined with the 4.2% frequency reduction results in 13.8%. The 460 V motors that exceed the 10% criteria are acceptable as follows.

The terminal voltages provided in Attachment C were determined using the conservative loading developed in the SEPS loading calculation vs. the actual loading discussed in Appendix A of the Engineering Evaluation. A sensitivity voltage drop case was run using the ETAP program with bus loading more representative of the actual loading analyzed in Appendix A of the Engineering Evaluation. The results showed a 1-2% improvement in the 460 V motor voltages with a few more of the safety related motors meeting the 10% combined criteria. The remaining motors are discussed further in the following paragraphs.

A literature search using text books and the internet was conducted and motor vendors were consulted to determine the effect of the reduced voltage and frequency on the motors that still do not meet the 10% combined criteria. The results are as follows.

The most significant effects of the reduced voltage and frequency operation are increased motor heating and a reduction in the available horsepower (hp) the motor can supply. These effects are interrelated in that the temperature will increase if the supplied hp remains the same as the voltage and frequency are reduced but the temperature increase will be minimized if the hp required by the loads decrease as the voltage and frequency reduces.

The temperature increase is typically in the range of 6-7° C. Given the motors' insulation ratings, this relatively small increase in temperature would not be an immediate failure concern but could effect the long term insulation life if the motors operated at the reduced voltage and frequency for an extended period of time. Considering the relative short duration of a LOOP event as compared to the motors' qualified life, the increased temperature should not effect the capability of the motors to perform their safe shutdown functions. Also, the temperature increase should not be as great as expected as explained in the next paragraph.

As explained in the affinity analysis section of Appendix A of the Engineering Evaluation, the power required by the centrifugal pumps and fans will be reduced to 88% of that required at rated frequency. Most safety related 460 V motors are operated at a hp less than rated. Most of these motors also have a service factor of 1.15. Together, these factors mean that the actual motor load at the reduced voltage and frequency should be close to the available capacity such that the temperature increase should be less than discussed in the previous paragraph.

It was also found that 60 Hz rated motors could generally be operated on a 50 Hz system as long as the voltage was reduced to maintain the appropriate volts per hertz ratio (V/Hz) ratio for acceptable motor excitation and the motor load was appropriately reduced to limit motor heating. This provides support for acceptable motor operation for the single genset condition since the reduced voltage and frequency is less than the 60/50 Hz operation and the V/Hz ratio is slightly reduced.

As discussed in the response to Question 11, the crew may take a procedure deviation to reduce engine load prior to TSC activation. At that time, voltage and frequency would return to rated eliminating the reduced voltage and frequency operation concern.

Based on the above discussion, it is concluded that the safety related motors are able to perform their safe shutdown functions given the reduced voltage and frequency condition for the single genset operation. See the response to question 14 for additional discussion of the effect on motors of the reduced voltage and frequency.

Response Preparer:	Randy C. Jamison [signature] for R. Jamison	Date: 9/22/09
Response Verifier:	Kenneth J. Letourneau [signature]	Date: 09-22-09

7. What is the impact on instrumentation, transformers, and component protection and bus work at reduced voltage & frequency?

Response: Seabrook's electrical equipment procurement specifications typically include power source requirements with a +/-10% voltage and a +/-5% frequency variation, as applicable, with no specific requirement to consider combined variations. In general, electrical component and cable overcurrent protection is sized with a minimum 1.25 margin so load operation at reduced frequency and voltage should not result in spurious protective device tripping.

Bus work is not directly affected by the reduced voltage and frequency operation, and there is sufficient margin in bus ratings to accept any increased current from loads operating at reduced voltage and frequency.

Transformer loading should decrease because the overall load decreases (see question 14). Since the % voltage decrease is greater than the % frequency decrease, the Volts per Hertz (V/Hz) ratio will be less at the reduced voltage and frequency point so transformer excitation should not be a concern. Likewise, PT and CT excitation would not be affected so that they can perform their functions to support electrical protection.

Plant instrumentation is typically powered from uninterruptible power supplies (UPSs) so the instrumentation power source is not directly affected by the voltage and frequency variation. The UPS has a rectifier section supplied by the 460 V ac power system and an inverter section supplied by the output of the rectifier or the station 125 V dc power system. Because of the rectification process, it is expected that the voltage and frequency variation will not effect the rectifier's dc output. If it is degraded, then the inverter would continue to operate on the 125 V dc power system providing adequate power to the instrumentation. Instrumentation that is supplied from the 120 V ac power system is expected to include an input power supply which would isolate the instrumentation from the voltage and frequency variation.

The station battery chargers are similar to the UPS rectifiers such that it is expected that the voltage and frequency variation will not affect the charger's dc output. If it is degraded, then the dc system would operate from the station batteries which have sufficient capacity (i.e., greater than 4 hours) until the operators take appropriate actions to restore voltage and frequency. Based on this discussion, it is concluded that the non-motor loads on the ac system will not be degraded by the reduced voltage and frequency in a manner that will effect their capability to perform their safe shutdown function. Motors are addressed in Question 6.

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8. What loads start on the sequencer - specifically for SEPS? How does operation of sequencer impact single SEPS operation? Is the sequence timing based on the recovery of the large power source?

Response:

The emergency power sequencer (EPS) starts the same safe shutdown loads whether the emergency bus is re-energized after a LOOP by the emergency diesel generator, both SEPS gensets operating in parallel, or one SEPS genset. As discussed in Appendix A of the Engineering Evaluation, the single SEPS genset load after the EPS completes load sequencing exceeds the adjusted base rating. The acceptability of this exceedence is demonstrated in the evaluation and the responses to these questions. The various loads are assigned to specific fixed EPS time steps to limit the magnitude of the load step and allow the diesel generator voltage and frequency to recover to acceptable levels prior to start of the loads at the next step. The minimum EPS time step interval is 5 seconds. Surveillance testing shows that the emergency diesel generators (large power source) are able to restore voltage and frequency prior to start of the loads on the next EPS step. The SEPS demonstration test showed that two SEPS gensets operating in parallel could likewise restore voltage and frequency prior to start of the loads on the next EPS step. No specific site sequence testing is available for the single genset operation. Cummins provided prototype test data for step load additions of 0-50%, 50-100%, 75-100%, and 0-100% of rated load that showed a single genset could recover voltage and frequency in at least 3.6 seconds which is less than the 5 seconds. It is also noted that for the LOOP event being analyzed, the large 4160 V motors are actually started with at least one step between them providing at least 10 seconds for recovery.

Response Preparer:	Randy C. Jamison R. Jamison	Date: 9-22-09
Response Verifier:	Kenneth J. Letourneau K.J.Letourneau	Date: 09-22-09

9. **Part 1** - How is the failure-to-run question evaluated? If one engine trips after successful loading, how would the remaining machine respond? **Part 2** - If that machine trips, what procedural guidance is available for recovery?

Response:

Part 1 – SEPS electrical margin analysis is based on a single SEPS DG being available at the beginning of the scenario (i.e., the second SEPS DG fails to start). If both SEPS DGs initially start, the load on Bus E6 may exceed the max load capacity for one SEPS DG as additional loads that are added by procedure. If one SEPS DG fails to continue to run, the remaining SEPS DG could trip off on overload resulting in another loss of power to the bus.

Part 2 - Operators would re-enter ECA-0.0 in response to the station blackout from trip of the SEPS genset and perform coping actions which include starting SEPS. If remote power restoration from the MCB is not successful, Operators would disable pump loads per Step 6 and attempt local actions to restore emergency bus power source, including starting SEPS in Step 8 and Attachment D. Once an emergency bus is energized, crew would either transition to ECA-0.1 or ECA-0.2 both of which provide SEPS loading guidance prior to starting pumps that were disabled in ECA-0.0 step 6.

Part 1

Response Preparer:	Kenneth J. Letourneau K J Letourneau	Date: 09-22-09
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Part 2

Response Preparer:	David F. Kelly	Date: 9/22/09
Response Verifier:	Kenneth J. Browne	Date: 9/22/09

10. Besides the loads identified in ECA-0.0, what other loads may be on the bus initially and added by the subsequent procedures?

***Response:** For a LOOP (non-SI) start, no additional loads would be expected to be on the bus initially. If only one SEPS DG is operating, no additional loads would be added in the short term based on the procedure guidance in Attachment A of ECA-0.0.*

Response Preparer:	David F. Kelly	Date: 9/22/09
Response Verifier:	Kenneth J. Browne	Date: 9/22/09

11. **Part 1** - How long could a single SEPS operate under the proposed conditions? **Part 2** - When can it be assumed that operators would take action to reduce load below 100%?

Response:

Part 1 – When the genset is loaded above the adjusted base rating the speed of the engine reduces resulting in a slight decrease in frequency and voltage and settles in at a constant speed. If the load changes such as a reduction in load the genset is regulated to the new load until the genset reaches the equilibrium point. This cyclical operation can continue for about 250 hours based on prototype testing. As part of prototype testing Cummins conducted a durability test. During this test the generator set was subjected to a minimum of 250 hours endurance testing and was operated at variable loads to verify structural soundness and durability of the design.

Part 2 - Operators would be locally monitoring SEPS status in approximately 20 minutes of the station blackout event. At this point, the Operating crew would determine if the engine load exceeds procedure upper limit and consult with plant engineering for guidance. The crew may take a procedure deviation to reduce engine load prior to TSC activation. The TSC, which is staffed within one hour, would provide guidance to reduce SEPS load as necessary within the SEPS mission time.

Part 1

Response Preparer:	Kenneth J. Letourneau K.J. Letourneau	Date: 09-22-09
Response Verifier:	Randy C. Jamison [signature] R. Jamison	Date: 9-22-09

Part 2

Response Preparer:	David F. Kelly [signature]	Date: 9/22/09
Response Verifier:	Kenneth J. Browne [signature]	Date: 9/22/09

12. In the event that the engine performs better than analyzed, what would be the impact on overcurrent protection?

Response:

If the engine performs better than expected such that the engine speed does not decrease to the same level, frequency and voltage would be slightly higher and the load would not decrease as much when using the affinity law and the load current would increase slightly. When considering the full adjusted base load of 2936 kW and normal frequency and voltage the generator output current would be 509 amps (2936 kW/4.16 kV X SQRT 3 x 0.8 = 509 amp). The overcurrent threshold setting of 511 amps for the AmpSentry would not be reached.

To demonstrate the effect if the engine performs better than expected such that the engine speed does not decrease to the same level, a case will be analyzed with a frequency reduction between rated frequency (no drop) and the 4.2% worst case from the test. For example, if frequency were to decreased by 3.0% the voltage would decrease by approximately 4.25% (See Figure 1). Applying the affinity law the load would also decrease. When considering this example the generator output current would be:

Portion of Adjusted base Load applicable to the affinity law = 2936 x 80% =2349 kW

Load not applicable to the affinity law = 2936 kW – 2349 kW = 587 kW

Affinity reduction (Power is proportional to the cube of shaft speed)

Affinity reduction @ 3%/58.2 Hz = $(58.2/60)^3$ = 0.913

Affinity reduced load =2349 kW x 0.913 = 2145 kW

Total load at 58.8 Hz = 2145 kW + 587 kW = 2732 kW

4.25% voltage reduction: = 4016 volts <<<.9575 x 4194 = 4016

Amperage at reduced voltage and reduced power:

I = P/ (V x SQRT 3 x PF) = 2732/(4.016 x SQRT 3 x 0.8) = 491 amps
At this intermediate point the current level of the AmpSentry setpoint is not reached.

AMPSENTRY threshold setting = 511 amps
AMPSENTRY 110% setting = 515 amps

Therefore, if the engine performs better than expected such that the engine speed does not decrease to the same level, the resulting current will be less than the threshold limit such that the overcurrent protection will not trip.

Response Preparer:	Kenneth J. Letourneau K.J. Letourneau	Date: 09-22-09
Response Verifier:	Randy C. Jamison [signature] R. Jamison	Date: 9-22-09

13. For a single SEPS operation, are there any additional operator actions? If so, have HRAs been completed?

Response:

No additional operator actions are required for long term load management. However, ECA-0.0 Attachment A provides guidance for single SEPS loading. Operators are instructed not to exceed SEPS load limit prior to starting pumps. Subsequent actions for SEPS load management are not explicitly modeled in the PRA. Such actions would be considered long term actions, performed in consultation with system experts including the TSC staff, and would be expected to be highly reliable.

Response Preparer:	David F. Kelly	Date: 9/22/09
Response Verifier:	Kenneth J. Browne	Date: 9/22/09

14. The combination of reduced voltage & frequency impact the efficiency of the motors and such things as magnetizing currents. Did you evaluate these conditions for each load to ensure the total load (magnetizing and working current) does not cause you to reach the generator overcurrent setpoint?

Response:

Appendix A of the Engineering Evaluation evaluated generator overcurrent protection considering both reduced frequency and voltage. First, the effect of the reduced frequency on the centrifugal pump and fan motor load was accounted for in the affinity rule analysis by reducing the power required by the motors by a cubed function from 2349 kW to 2067 kW. Second, the remaining 587 kW of non-centrifugal pump and fan motor load was conservatively assumed to be constant power loads, i.e., not reduced by the reduced frequency. Third, these were combined to provide a total load at the reduced frequency of 2654 kW (2067 kW + 587 kW). This total load was then divided by the 8% reduced voltage of 3860 V to provide a working current of 496 A. Using the minimum voltage results in a worst case maximum current, i.e., the lower the voltage for a given load, the higher the current. The 496 A is less than the 511amp Ampsentry threshold setting so the electrical protection will not trip. Magnetizing current decreases in direct proportion to the voltage reduction so its contribution was not separately quantified.

Response Preparer:	Randy C. Jamison R. Jamison	Date: 9-22-09
Response Verifier:	Kenneth J. Letourneau K J Letourneau	Date: 09-22-09

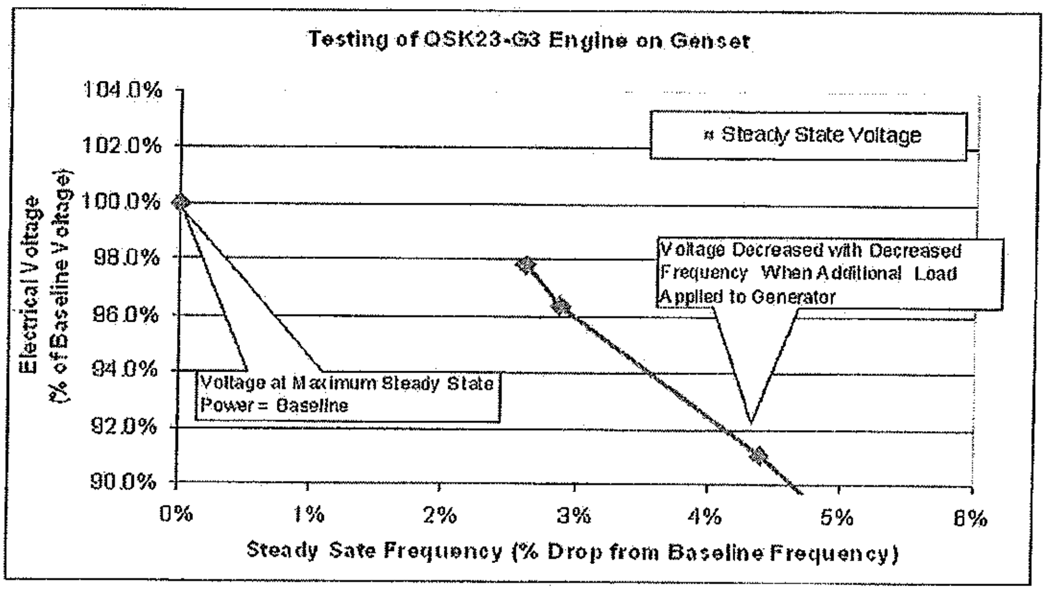
Letourneau, Kenneth

From: cary.j.marston@cummins.com
Sent: Friday, August 28, 2009 12:29 PM
To: Letourneau, Kenneth; Jamison, Randy; Kotkowski, Gerald
Cc: Weeks, Doug; Collins, Michael; Noble, Rick; jeff.g.anderson@cummins.com
Subject: Voltage versus Frequency for QSK23-G3 Test

Ken, Randy and Gerry,

Per our discussion, please find here the updated voltage curve attached showing the actual points run on our tests.

Cary



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1

Letourneau, Kenneth

From: cary.j.marston@cummins.com
Sent: Friday, August 28, 2009 7:09 AM
To: Letourneau, Kenneth
Cc: Weeks, Doug; Kotkowski, Gerald; jeff.g.anderson@cummins.com; Collins, Michael; Jamison, Randy; Noble, Rick
Subject: RE: FW: FW: Cummins Letter for Seabrook Station Generator Sets

Ken,

Here are the plots we discussed last night. These show the results obtained for a QSK23-G3 engine on a genset from our test facility.

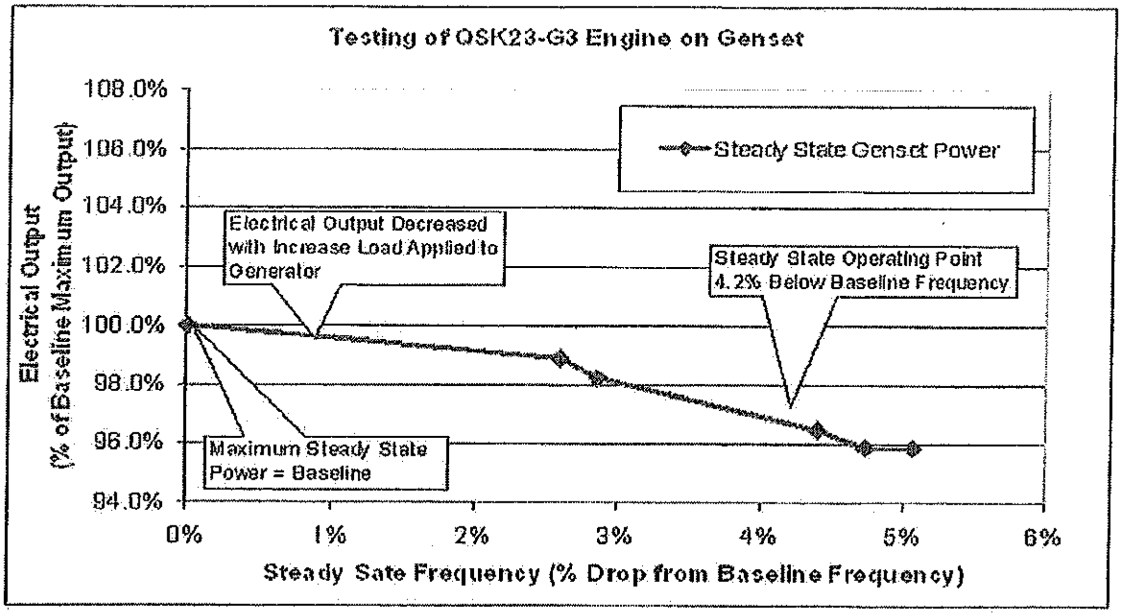
The first figure shows the steady state power versus frequency for operation below the target frequency. This is generated by adding load above 100%, which "lugs the engine / genset" down to a lower speed / frequency.

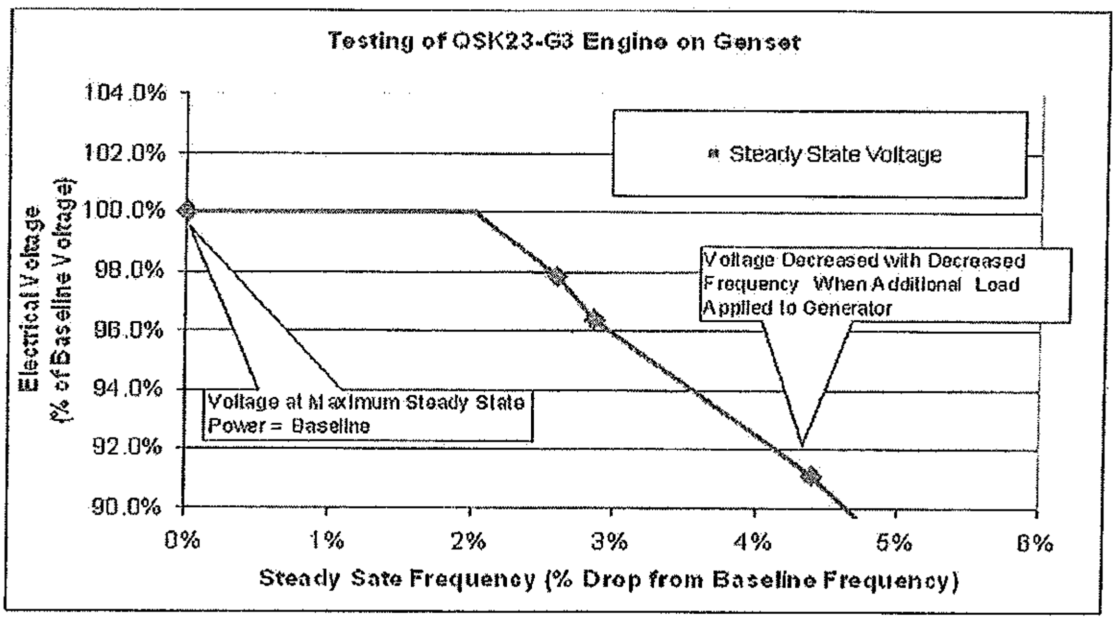
The second figure shows the volts / hz curve for these tests. Please note that the voltage at 4.2% lower frequency, is 92% of the baseline voltage.

The second figure shows the same data, with the "customer load" data you provided, based on your analysis. The intersection of these curves occurs at a frequency 4.2% below the baseline frequency. This is where the genset load matches the "customer load".

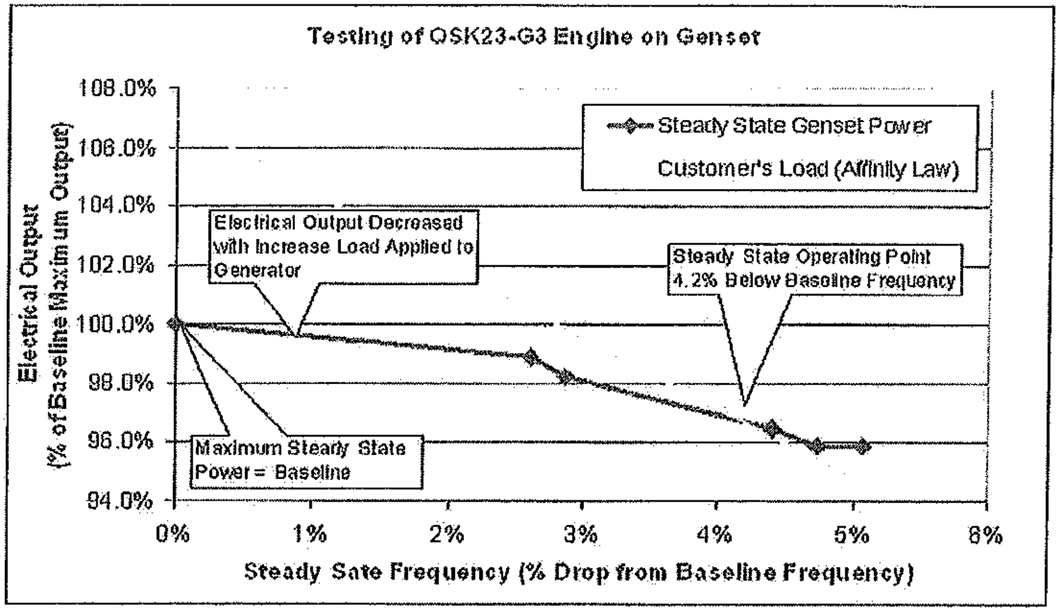
Sincerely,

Cary


Testing of QSK23-G3 Engine on Genset
Steady State Genset Power
Electrical Output Decreased with Increase Load Applied to Generator
Steady State Operating Point 4.2% Below Baseline Frequency
Maximum Steady State Power = Baseline
Electrical Output (% of Baseline Maximum Output)
Steady Sate Frequency (% Drop from Baseline Frequency)
108.0%
106.0%
104.0%
102.0%
100.0%
98.0%
96.0%
94.0%
0%
1%
2%
3%
4%
5%
6%


Testing of QSK23-G3 Engine on Genset
Steady State Voltage
Voltage Decreased with Decreased Frequency When Additional Load Applied to Generator
Voltage at Maximum Steady State Power = Baseline
Electrical Voltage (% of Baseline Voltage)
Steady Sate Frequency (% Drop from Baseline Frequency)
104.0%
102.0%
100.0%
98.0%
96.0%
94.0%
92.0%
90.0%
0%
1%
2%
3%
4%
5%
6%

REGULATORY CONFERENCE – DGB SDP
Questions from Chris Cahill (and Larry Scholl & Dan Orr), NRC Region 1
September 11, 2009



Cary J. Marston
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Appendix A

Electrical Analysis of SEPS Capacity

September 22, 2009

Kenneth J. Letourneau *K J Letourneau* Preparer for Appendix A	*09-22-09* Date
Randy C. Jamison *[illegible] for R. Jamison* Independent Reviewer for Appendix A	*9-22-09* Date

APPENDIX A

TABLE OF CONTENTS

LOP Loads With One SEPS Generator Set
Engineering Evaluation

The Supplemental Electrical Power System (SEPS) provides two diesel generator (DG) sets for powering the emergency loads during a Loss of Power (LOP) event. This evaluation will determine if one SEPS DG can support the emergency loads based on actual running values.

Background

The design of the SEPS is capable of providing the required safety related loads in the event of a loss of offsite power if both emergency diesel generators fail to start and load. During these events it is assumed that there is no seismic event or an event that requires safeguards actuation (SI, CBS, CVI, CI, etc.). Selection of the required loading connected to SEPS is based on PRA Evaluation 03-007. In addition to providing power to the required loads, the total combined output of the SEPS system can supply either the RHR pump or the SI pump. The analysis conservatively includes the RHR pump but it would not be sequenced on unless already running prior to the LOP. The SEPS system equipment except the emergency bus breakers are classified as non-safety-related, non-Class 1E, non-seismic (Safety Class N) and are not within the requirements of the Operational Quality Assurance Program (OQAP).

The Supplemental Electrical Power System provides two 2700 kW (3375 kVA) gensets for a total of 5400 kW capacity with a slight reduction for SEPS auxiliaries (138 kW). The highest total calculated load for Bus E6 load is 4425 kW. The emergency power requirements are based on a modified (LOP) load and are described in Calculation C-S-1-38016. During commissioning a test was performed which simulated an LOP event with SEPS aligned to Bus E6. The recorded results show the total connected load after the completion of Emergency Power Sequencer (EPS) step 12 as 2903 kW with a voltage of 4183 volts at SEPS-CP-1.

The rating of a single SEPS generator is 2832 kW (105°C) and the nominal engine gross output kWm is 2790 kW (3740 BHP). The generator 125°C rating is 3024 kW.

An extended load duration factory test was conducted on each genset. Genset BO4K395120 obtained an output of 2717 kW and genset BO4K395130 obtained an output of 2727 kW. The achieved output for these tests are considered the nominal base rating.

After gensets have operated 100 hours the available output increases by one percent as provided by Cummins. This increase is attributed to engine break in. Once the engine operates approximately 100 hours the frictional losses are reduced which increases the available power for output generation. When applying this factor to the test results the available output capacity for genset BO4K395120 increases to 2744 kW and genset BO4K395130 increases to 2754 kW. These ratings are referred to as the adjusted base rating. The output capacity for genset BO4K395120 the smaller of the two is used for calculations in this evaluation since the loading can be supplied by either genset.

Cummins Power Generation Division was contacted to ascertain genset response data during overloaded conditions. The text and tables below provide the expected results for the Seabrook Cummins gensets.

SEPS Load Evaluation

The SEPS system was tested by Complex Procedure OS05-01-02 and documented on Work Order WO 0513168. The test performed a simulated LOP event with SEPS aligned to Bus E6. The recorded results show the total connected load after the completion of Emergency Power Sequencer (EPS) step 12 as 2903 kW with a voltage of 4183 volts. This is 66% of the calculated load as shown in calculation C-S-1-38016. The loading evaluation will use the actual recorded value since it is more indicative of the real loads as compared to the calculated load.

The SEPS loading was measured at SEPS-CP-1 control panel using a Square D Digital Power meter Class 3020. Using the vendor's specifications in FP35421 the accuracy is determined as follows:

Power function meter accuracy (PA) = +/- 0.5% (reading) +/- 0.05% (Full scale adjustment) = +/- 0.55%

Meter drift (MD) = assumed +/- 0.5%

Instrument transformer accuracy (IA) = +/-0.3%

Reading Accuracy = $\sqrt{(IA)^2 + (PA + MD)^2} = \sqrt{0.09\% + 1.1\%}$ =1.09%

Using +1.09% meter accuracy the kW load reading is applied to the actual test value.

2903 kW x 1.0109 =2935 kW

The test alignment for service water, PCCW, and charging pumps was the same as for responding to an actual LOP using procedure ECA 0.0, Loss of all AC Power.

With only one SEPS genset running 60 kW for the radiator cooling fan for the INOP genset can be subtracted from the total recorded load. Since the load metered point during the test was at SEPS-CP-1 the SEPS auxiliaries were not measured. To account for these loads an additional 78 kW is added to the test load resulting in a load of 3013 kW.

SEPS auxiliary loads = 138 kW (Ref. Calculation C-S-1-38016)

138 kW – 60 kW = 78 kW

2935 kW + 78 kW = 3013 kW

During testing all of the 4 kV motors were operating in similar conditions as in an LOP event except the RHR and the EFW pump motor. Under normal full power operations with an LOP without SI the RHR pump would not be loaded on at step three of the load sequencer if it was not already operating before the LOP. During the glycol leak the RHR pump was not operating which is typical during normal power operations. The RHR pump motor would account for a further reduction. The RHR pump was in the recirculation mode during the test with a load of 203.2 kW. The reduction of 203.2 kW would result in a total load of 2810 kW.

3013 kW -203.2 kW = 2810 kW

The RHR pump was operated on 02/24/09 for 39 minutes for surveillance. This evaluation assumes the pump as not being available as an emergency load. The PRA evaluation will address the probability of this pump being available as an LOP load.

The EFW pump was in the recirculation mode during the test with a flow of approximately 225 gpm and BHP of 560 (94MMOD525). In actual operation, the EFW pump, at 650 gpm, requires 720 BHP. This 160 HP difference would result in an additional load to the obtained test load of 125.9 kW resulting in a load of 2936 kW.

2810 kW + 125.9 kW = 2936 kW (2936 kW will be used as adjusted base load)

During the period of 02/02/09 to 03/01/09 the selector switch SS-5441 for FAH-FN-11B was in the NORMAL mode which would not allow the fan to be sequenced on during an LOP except for the time that a surveillance was being performed. Specifically, this fan was on for twelve hours to perform surveillance during the evaluated time period on 02/06/09. When the fan is in the NORMAL mode a deduction of 53 kW is used to reduce the load to 2883 kW.

2936 kW – 53 kW = 2883 kW

However, during this same period that the FAH fan was available (in NORMAL mode), CAH-FN-1D was not available for an automatic start during an LOP. When considering the 106 kW for this fan during this period the SEPS loads would be reduced to 2830 kW.

2936 kW – 106kW = 2830 kW

The FAH fan was also available for a time period between 2/20/09 and 02/21/09. The attached plot shows the FAH fan running at the same time the CBA B Train equipment was not available. For all other times this evaluation assumes the FAH fan as not being available as an emergency load during the evaluated period and not included.

The Control Building CBA system equipment CBA-P-435B and CBA-CP-178 were included as loads during the SEPS demonstration test. Pump CBA-P-434B or CBA-P-435B is selected to run but not both for a load of 13 kW. When one of the pumps is in operation the CBA chiller control panel CP-178 also operates with a load of 67 kW. During the evaluated period up until 02/23/09, this equipment was in OFF and not available for an automatic start for an LOP event. When the equipment was not available the total emergency load would be reduced to 2803 kW.

2883 kW – 13 kW – 67 kW = 2803 kW

LOP Loads With One SEPS Generator Set
Engineering Evaluation

To determine a more precise loading for the evaluated period, the following table and attached plot were used showing the various equipment availability and loading. The following composite loading shows the major time periods and load variations using the adjusted base load of 2936 kW from the demonstration test.

Date (Time)	Unavailable Loads	Base Load Deduction kW	Available Load kW
2/1/09(2330) to 2/6/09 (0105)	CBA-P-434B/435B CBA-CP-178 FAH-FN-11B CAH-FN-1D	13 67 239 53 106	2697
2/6/09 (0105) to 2/6/09 (1127)	CBA-P-434B/435B CBA-CP-178 CAH-FN-1D	13 67 186 106	2750
2/6/09 (1127) to 2/9/09 (1013)	CBA-P-434B/435B CBA-CP-178 FAH-FN-11B CAH-FN-1D	13 67 239 53 106	2697
2/9/09 (1013) to 2/20/09 (0504)	CBA-P-434B/435B CBA-CP-178 FAH-FN-11B	13 67 133 53	2803
2/20/09 (0504) to 2/20/09 (1713)	CBA-P-434B/435B CBA-CP-178	13 67 80	2856
2/20/09 (1713) to 2/23/09 (803)	CBA-P-434B/435B CBA-CP-178 FAH-FN-11B	13 67 133 53	2803
2/23/09 (0803) to 3/1/09	FAH-FN-11B	53	2883
Adjusted Base Load			2936

Calculation C-S-1-38016 also analyzed operation of the Cooling Tower pumps on the SEPS DGs. The Train B Cooling Tower pump was not operating between 2/2/09 and 03/01/09 and does not need to be included in this loading evaluation. The Cooling Tower pump and fans are only operated periodically and not included in the normal base load.

SEPS Voltage Evaluation

Based on testing performed by Cummins on the QSK class of gensets, the voltage and frequency begins to decrease slightly as loading is increased above the genset base nameplate rating. The table below indicates these reductions associated with the level of overload (See Attachment E).

Table 1

% Load Above Genset Capacity	% Frequency Reduction/Hz	%Voltage Reduction
7.0	4.2	8%

The cumulative kW loading from Step 1 up to EPS step 8 is within the adjusted base rating of one SEPS genset and voltage and frequency are maintained. At step 9 when the SW-P-41D is sequenced on and at step 12 the load exceeds the adjusted base rating of one SEPS genset. Table 2 below provides the loading at these steps associated with the cumulative kW load and the percent loading above the adjusted standby capacity. When calculating the step loading the obtained test kW adjusted base loading of 2936 kW including tolerances is used. To determine the percent overload the genset adjusted base rating of 2744 kW is used.

Table 2

EPS Step	Calculated kW Loading	% Over Adjusted Base Rating
1 through 8	2936 – 494 -131 = 2311	0
9	2311 + 494 = 2805	(2805 kW/2744 kW) -1 X100 = 2.2%
12	2805 + 131 = 2936	(2936 kW/2744 kW) -1 X100 = 7%

To determine the available voltage at the emergency loads, voltage study cases using ETAP were performed. ETAP is the software program that is used at Seabrook Station for voltage regulation calculations. The ETAP model consists of a one line diagram of the on-site electrical distribution system which includes the characteristics of plant loads, interconnecting cables, normal power supplies and emergency power supplies including SEPS.

Since the recorded test voltage of 4183 volts was measured at SEPS-CP-1 the voltage at the SEPS generator terminals must be calculated to account for the interconnecting cables. This is determined by using an iterative process where the assumed voltage at the generator terminals is adjusted until the test voltage level at SEPS-CP-1 is obtained. To replicate the loading during the SEPS commissioning testing the ETAP Step 12 steady state full load is used. When using this process the voltage for the SEPS DG output is calculated as 4194 volts.

Voltage case studies were performed for steps 7 (FW-P-37B start), 9 (SW-P-41D start) and for the steady state loading after step 12 which will be referred to as step 12P. For the motor starting cases the previously started loads are analyzed as running. For step 12P all loads are analyzed as running.

During starting conditions the voltage dip at the generator terminals is determined by the generator lock rotor starting curve contained in Calculation C-S-1-38016. This curve is used for study cases 7 and 9. The curve is based on 4160 volts and is adjusted for the SEPSDG output voltage ([100 - % DROP] X 4194). For EPS Step 12P the generator output voltage is reduced by 8% for a 92% DG terminal voltage (92.8 on a 4160 volt base) as a result of the 7% overload. Table 3 below provides the generator terminal voltages that are used for these study cases.

Table 3
[2]

EPS Step	% Transient Voltage Drop	SEPS DG % Voltage
7 (5051 skVA)	24	76.6 (3187)
9 (4016 skVA)	20	80.7 (3357)
12P	8%	92.8 (3860)

The obtained voltages at these steps for the equipment are listed in Attachment C and are evaluated below.

Per REG GUIDE 1.9 the general industry practice is to specify a voltage reduction of 10–15 percent when starting large motors from large-capacity power systems, and a maximum voltage reduction of 25–30 percent when starting these motors from limited-capacity power sources such as diesel generators. When evaluating the results of the calculated voltages using for the ETAP study cases a maximum voltage reduction between 25-30 percent will be used.

Voltage study case for Step 7 calculates the voltage reduction for the loads when the EFW pump (FW-P-37B) is started. The calculated voltage for the 4 kV motors are in the range of 78.5% to 78.9%. The calculated voltages for the 460 volt loads are in the range of 72.8% to 78.7%. Using the criteria in REG GUIDE 1.9 the calculated voltages during starting of the EFW pump are acceptable.

Voltage study case for Step 9 calculates the voltage reduction for the loads when the Service Water pump (SW-P-41D) is started. The calculated voltage for the 4 kV motors are in the range of 82.3% to 83.2%. The calculated voltages for the 460 volt loads are in the range of 77.4% to 83%. Using the criteria in REG GUIDE 1.9 the calculated voltages during starting of the SW pump are acceptable.

Voltage study case for Step 12P calculates the steady state voltages for loads when the SEPS DG is overloaded by 7%. The calculated voltage for all 4 kV motors and 460 volt loads receive more than 90%. Using the criteria in REG GUIDE 1.9 the calculated voltages during steady state conditions are acceptable.

LOP Loads With One SEPS Generator Set
Engineering Evaluation

Affinity Law Power Reduction

Based on the affinity laws, power is proportional to the cube of motor shaft speed for centrifugal pumps and fans. A reduction in generator frequency results in a reduction of power to the motor loads and therefore the total connected running load is also reduced. The following calculations are used to determine the percent of motor load contribution to the adjusted base load and determines the load reduction based on the affinity law:

% Overload above adjusted base rating:

2936 kW/2744 kW = 7%

Frequency Reduction for applied Load (See Attachment E):

7.0% Overload Equilibrium Point = 4.2% frequency reduction

Total Centrifugal Pump & Fan motor load = 2979 kW (W/O RHR Pump)
(Ref: C-S-1-38016 and 06DCR008)

Total Calculated load – RHR Pump – One SEPS Fan = 3741 kW (Ref: C-S-1-38016 and 06DCR008)

% Calculated Motor Load Applicable to Affinity Law = 2979/3741 = 80%

Portion of Adjusted base Load applicable to the affinity law = 2936 x 80% =2349 kW

Load not applicable to the affinity law = 2936 kW – 2349 kW = 587 kW

Affinity reduction (Power is proportional to the cube of shaft speed)

Affinity reduction @ 4.2%/57.48 Hz = $(57.48 / 60)^3 = 0.88$

Affinity reduced load =2349 kW x 0.88 = 2067 kW

Total load at 57.48 Hz = 2067 kW + 587 kW = 2654 kW

After the generator is overloaded by 7% the steady state load would be reduced to 2654 kW with the frequency reduction of 4.2%.

SEPS Generator Protection Evaluation

The SEPS genset protection is set for a load that exceeds 110% of the nameplate capacity and will trip at 2970 kW (515 amps) after 235 seconds (See attachment B).

$$1.1 \times 2700 \text{ kW} = 2970 \text{ kW} \quad \text{or} \quad 1.1 \times (3375 \text{ kVA}/[4.16 \text{ kV} \times \sqrt{3}]) = 515 \text{ amperes}$$

LOP Loads With One SEPS Generator Set
Engineering Evaluation

The overcurrent protection is provided by AmpSentry which is part of the generator protection integral to the PowerCommand control. The AmpSentry uses input signals from instrument transformers that sense the generator output. To determine the accuracy of the current loop an assumed accuracy of +/- 1% will be used. When using this accuracy and applying to the 110% trip setting the minimum trip point is determined as follows:

$$(110\% - 1\%) \times 2700 \text{ kW} = 2943\text{kW or}$$

$$(110\% - 1\%)(3375 \text{ kVA}/[4.16 \text{ kV} \times \sqrt{3}]) = 511 \text{ amperes}$$

A load of 109% or 2943 kW will be used as a conservative threshold since the generator long time overload protection at the generator control panel is disabled below 110% with consideration of the accuracy of the overload protection.

The 2943 kW corresponds to a threshold current of 2943kW/(4.16 kV x 3 SQRT x 0.8) = 511A

The adjusted base load corresponds to a load current of 2936 kW/(4.16 kV x 3 SQRT x 0.8) = 509A

When the running load exceeds the adjusted base genset rating the diesel engine encounters a slight drop in speed. As a result of the slight drop in speed the steady state power reduced with a drop in voltage to 92.0% (8% Voltage reduction) and frequency decreases by 4.2% for a load of 7.0% over base capacity. Power is proportional to the cube of shaft speed. A reduction in frequency results in a reduction of power and therefore the total running load is also reduced to 2654 kW (See affinity law reduction above).

With a voltage reduction of 8% in generator output voltage of 4194 v the output voltage would be 3860 volts. The drop in voltage and frequency will also result in a drop in the steady state loading. To determine the current level of the load when this occurs the steady state power reduction from applying the affinity law and expected voltage reduction will be used.

8% voltage reduction: (See Table 3) =	3860 volts
Total load at 57.48 Hz =	2654 kW
Amperage at reduced voltage and reduced power:	
I = P/ (V x SQRT 3 x PF) = 2654/(3.86 x SQRT 3 x 0.8) =	496 amps
AMPSENTRY threshold setting =	511 amps

When using 109% of the genset nameplate capacity it can be seen that one genset would not trip on long time overload for a normal base load of 2936 kW when the power consumed by the motor loads are reduced from the decrease in frequency.

The maximum calculated load for the normal base load of 2936 kW does not exceed the generator winding thermal limit (125°C). Per the generator test certificate the 125°C load capability is 3024 kW.

SEPS Diesel Engine Evaluation

The diesel engine has a power output rating of 2790 kW (flywheel) for Standby Service. This rating is less than the ultimate capability of the engine because of inherent conservatism in vendor ratings.

Typically maximum engine power is controlled by the power limiter setting. This setting can be set to limit the maximum power output of the engine. This setting has been disabled such that there is no governed power limit. If the engine monitoring parameters are within range, the genset limitation is the generator protection. When monitoring the engine parameters during periodic surveillance tests it was observed that the lube oil and jacket water cooling systems had high margins to the shutdown points during full load operation. This would indicate the ability to support an increased load above nameplate.

Based on Cummins testing of similar QSK gensets with the same control system and fuel system the engine response to various incremental load increases over the nominal base rating resulted in slight decreases in frequency and voltage. Although there was a decrease in voltage and frequency the engine continued to operate. As discussed in the loading evaluation, the engine is capable of supporting a generator overload over the adjusted base rating to supply the adjusted base load.

Based on the testing (See Table 1) the overcurrent is likely to trip first since the frequency reduction for 110% overload would not reach the under frequency setpoint. Since the load is not expected to reach the 110% trip point or under frequency trip setting the engine should support the load.

If the load exceeds the engine adjusted base rating there will be a slight decrease in engine speed. Based on the evaluation in Attachment D it was determined that the safety related pumps would operate to perform their safety related functions with a 4.2% frequency reduction on the SEPS generator.

Operator Action

Operating a SEPS genset over nameplate rating for an extended period of time is not desirable. In the event that this condition was to occur there is sufficient time to reduce loading after personnel are dispatched to the SEPS equipment enclosures to determine the running status.

Emergency Operating Procedure ECA-0.0 provides actions to restore emergency bus power in response to a station blackout event. ECA-0.0 step 5b provides actions to close the SEPS supply breaker to the emergency bus in the event the main Emergency DGs fail to start. It is estimated that time for the connecting the SEPS DGs to the bus is approximately eight minutes. Once the sequencer connects loads to the bus, ECA-0.0 step 5j provides direction to maintain SEPS load limit per Attachment A. This Attachment provides direction to locally dispatch personnel to the SEPS equipment to determine status and load condition. It is estimated that time to arrive at the SEPS gensets is approximately 10 minutes of being notified by control room. In the event that only one SEPS DG is running and SEPS-CP-5 or CP-6 indicates an overload kW condition, SEPS DG-2A/2B Panel SEPS-CP-5/6 local alarm responses would direct operators to reduce load (Ref. LAR-SEPS-CP-5 or LAR-SEPS-CP-6). ECA 0.0, Attachment A also provides instruction to limit start of additional pumps to prevent exceeding SEPS nameplate load capabilities. This action will provide the necessary steps to manage the loading within the nameplate capabilities in the event of an alarm condition and provide the assurance of continued operation of the genset to supply the safety related loads.

References

[1] Calc. C-S-1-38016 (06DCR008); Supplemental System Voltage Regulation

[2] FP35489 2195350 001 SEPS Genset Data Package

[3] EMAIL, 8/27/09, C.J.Marston/K.Letourneau (Cummins/Nextera); Genset response to overloaded conditions

[4] EMAIL, 8/24/09, C.J.Marston/K.Letourneau (Cummins/Nextera); % Overload, frequency & voltage reduction

[5] EMAIL, 8/19/09, C.J.Marston/K.Letourneau (Cummins/Nextera); Genset adjusted base capacity basis

[6] Work Order 0513168; Perform SEPS Demonstration Test on Bus E6

[7] FP35421; Square D Digital Power Meter Class 3020

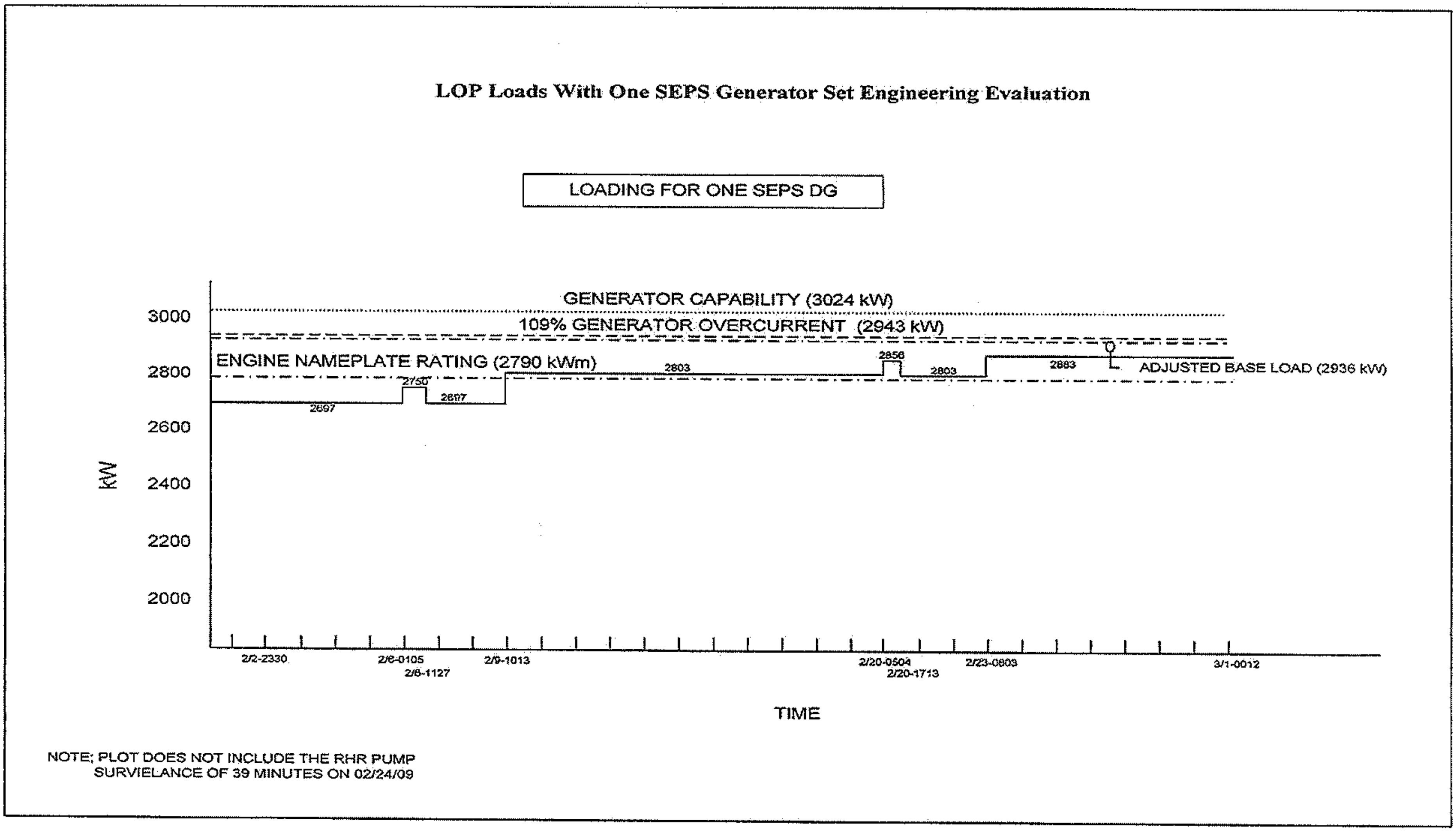
LOP Loads With One SEPS Generator Set
Engineering Evaluation

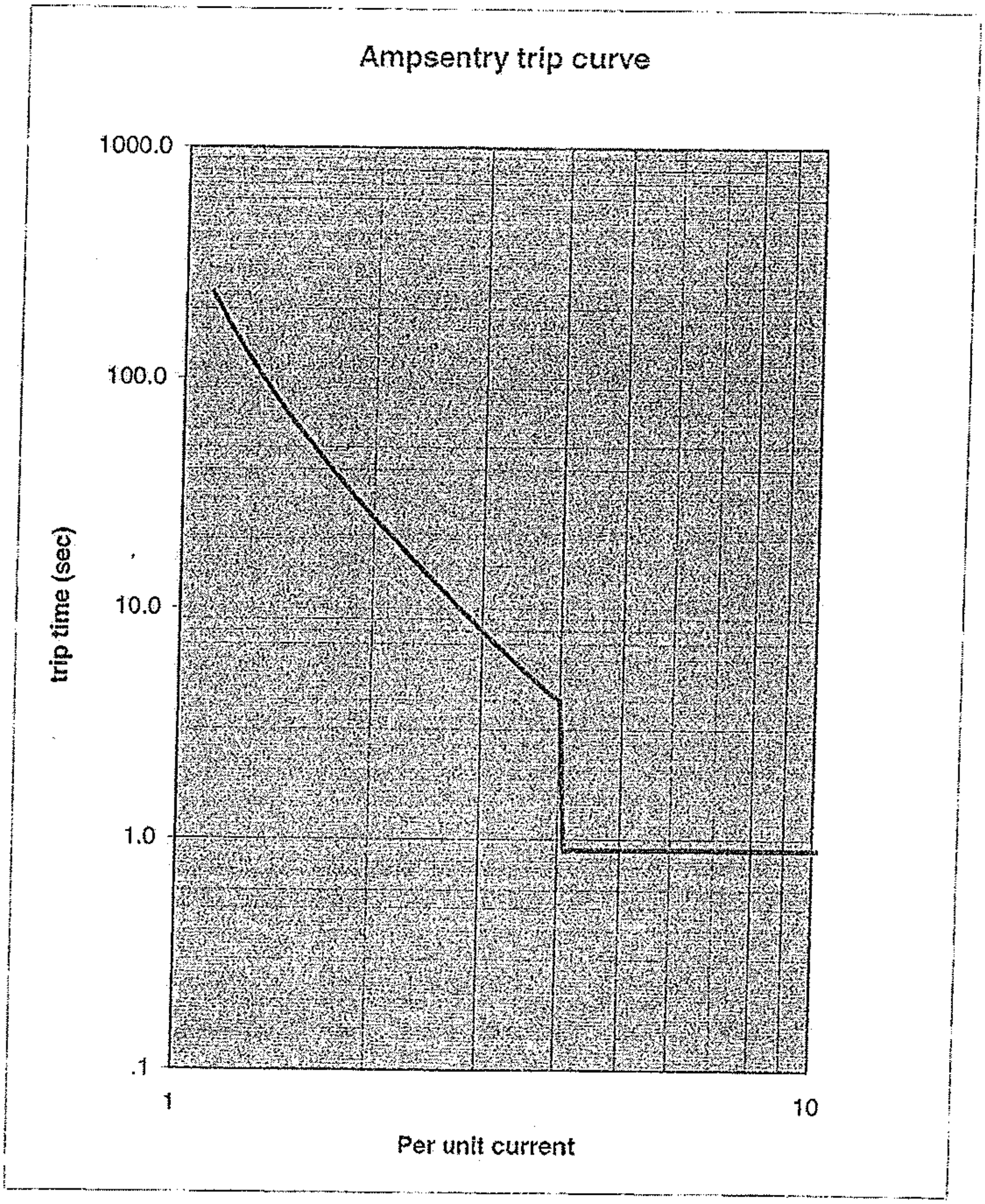
Conclusion

When considering the loading profile for the evaluated period of 02/02/09 to 03/01/09 and the adjusted base load (2936 kW), the total load is within the capability of a single SEPS genset. The single genset can supply the load without tripping. The loading above the adjusted base rating results in a drop in generator frequency and voltage. The safe shutdown loads can perform their function to mitigate the LOP event at the reduced voltage and frequency values.

See Attachment F for the responses to questions received from the NRC; these responses provide additional support that the safe shutdown loads can perform their function.

Prepared by: *Kenneth J. Letourneau* K.J. Letourneau	Date: 09-22-09
Reviewed by: *Randy C. Jamison* for R. Jamison	Date: 9-22-09
Mechanical Systems Engineer: *Thomas A. Schulz* (Systems Input) for T. Schulz per Telecon	Date: 9/22/09
Mechanical Systems Engineering Review: (Systems Input) *Christine I. Cronin* Christine I. Cronin	Date: 9/22/09
Approver: *Michael K. Collins* Mike K. Collins	Date: 9/22/09


LOP Loads With One SEPS Generator Set Engineering Evaluation
LOADING FOR ONE SEPS DG
GENERATOR CAPABILITY (3024 kW)
109% GENERATOR OVERCURRENT (2943 kW)
ENGINE NAMEPLATE RATING (2790 kWm)
ADJUSTED BASE LOAD (2936 kW)
3000
2800
2600
2400
2200
2000
kW
2697
2750
2697
2803
2856
2803
2883
2/2-2330
2/6-0105
2/6-1127
2/9-1013
2/20-0504
2/20-1713
2/23-0803
3/1-0012
TIME
NOTE; PLOT DOES NOT INCLUDE THE RHR PUMP
SURVIELANCE OF 39 MINUTES ON 02/24/09


Ampsentry trip curve
1000.0
100.0
10.0
1.0
.1
trip time (sec)
1
10
Per unit current

PowerCommand Control Amp Sentry Time-Over-Current Characteristic Table

$t = 43.5 / (I - .67) ^ 2$

I	t
1.1	235.3
1.2	154.9
1.3	109.6
1.4	81.6
1.5	63.1
1.6	50.3
1.7	41.0
1.8	34.1
1.9	28.8
2	24.6
2.1	21.3
2.2	18.6
2.3	16.4
2.4	14.5
2.5	13.0
2.6	11.7
2.7	10.6
2.8	9.6
2.9	8.7
3	8.0
3.1	7.4
3.2	6.8
3.3	6.3
3.4	5.8
3.5	5.4
3.6	5.1
3.7	4.7
3.8	4.4
3.9	4.2
4	3.9

BUS AND MOTOR VOLTAGES DURING SEPS DIESEL GENERATOR LOAD SEQUENCING FOR

BUS E6

Equip.	7	9	12P
SEPS-DG-2A or 2B	3187	3357	3860
SEPS-SWG-1	3177	3347	3854
SEPS-CP-1(A5C)	3162	3332	3845
BUS-6	3162	3332	3845
CS-P-2B	3157	3328	3841
CC-P-11D	3157	3327	3841
SW-P-41D	-	3290	3834
FW-P-37B	3140	3324	3838
US-61	352	372	431
MCC-611	351	372	430
DG-C-2B	-	-	429
MCC-612	350	371	430
PAH-FN-42B	346	367	426
EPA-FN-47B	342	363	423
CS-P-3B	335	356	417
EAH-FN-31B	341	362	422
FAH-FN-11B	344	365	424
EAH-FN-180B	335	357	418
AS-V-176	348	368	426
EDE-I-1B	348	369	428
EDE-I-1F	348	369	428
SW-V-5	345	365	424
MCC-614	349	370	429
SWA-FN-38B	347	368	427
SW-V-29	347	367	426
MCC-615	351	372	431
CC-P-322B	339	360	420
FW-FV-4214B	346	366	424
US-62	361	382	442
EAH-FN-5B	352	373	434
CBA-CP-178	356	377	438
MCC-621	361	382	441
CBA-FN-32	-	-	440
CBA-FN-16B	358	379	439
RH-FCV-611	355	375	434
EDE-I-1D	359	380	440

LOP Loads With One SEPS Generator Set
Engineering Evaluation
ETAP RESULTS

Equip.	7	9	12P
US-63	362	379	434
CAH-FN-1A	355	373	429
CAH-FN-1B	355	372	428
CAH-FN-1D	-	372	429
SA-SKD-137B	-	-	423
MCC-631	361	378	434
CS-P-243B	352	370	426
CS-HCV-190	347	363	416
CAH-FN-2B	-	-	425
CAH-FN-2D	-	-	427
US-64	364	384	443
MCC-641	364	384	443
SWA-FN-70	362	383	441
SEPS-PP-1	366	385	444

ATTACHMENT C PAGE 2 OF 2

LOP Loads With One SEPS Generator Set
Engineering Evaluation
Frequency Reduction on Pump Performance

Following a LOP event, ECA 0.0 verifies that the following pumps are running:

Charging pump
Thermal barrier cooling pump
PCCW pump
EFW pump
SW or cooling tower pump

Cummins has indicated that for the anticipated single SEPS genset loading following a LOP, a frequency decrease of approximately 4.2% could occur. Accordingly, these pumps will be evaluated for operation at reduced frequency.

PROTO-FLO Version 6.0 was used in this evaluation. PROTO-FLO is a Windows based program used to perform steady-state analyses of thermal-hydraulic systems. Seabrook currently has two PROT-FLO models developed for the Service Water System and the Emergency Feedwater System. For the Charging Pump, PROTO-FLO was utilized by inputting pump curve data and then reducing the speed of the pump by 4.2% to obtain the reduced pump curve data.

Thermal Barrier Cooling Pump

Thermal barrier cooling flow is 214 gpm (SDS 8/20/09 0900) or 53.5 gpm/RCP. In accordance with the reactor coolant pump vendor manual, W120-21, the minimum required flow to the thermal barrier cooler is 40 gpm. The actual flow is 33.75% greater than this minimum flow requirement. Sufficient margin exists to ensure adequate flow with 4.2% underfrequency.

Service Water Pump

In the LOP alignment, the service water system is required to deliver 7800 gpm to the PCCW heat exchangers and 900 gpm to the diesel generator heat exchangers (Ref: 4.3.08.57F). The existing ProtoFlo model of the service water system was modified by adjusting the existing pump to 95.8% of its design speed. The resulting heat exchanger flows are 10,533 gpm and 1,991 gpm respectively, which are higher than the minimum required. There is no adverse impact on service water system flows from the 4.2% underfrequency.

Emergency Feedwater Pump

The EFW system is required to provide a minimum of 470 gpm to three intact steam generators or 470 gpm to 2 steam generators. The existing ProtoFlo model of the EFW system was modified by adjusting the existing pump to 95.8% of its design speed. For all combinations of 2 or 3 steam generators, flows exceed the minimum required flow of 470 gpm (544-546 gpm for 2 SG, 615 – 616 gpm for 3 SG). There is no adverse impact on EFW flows from the 4.2% underfrequency.

Charging Pump

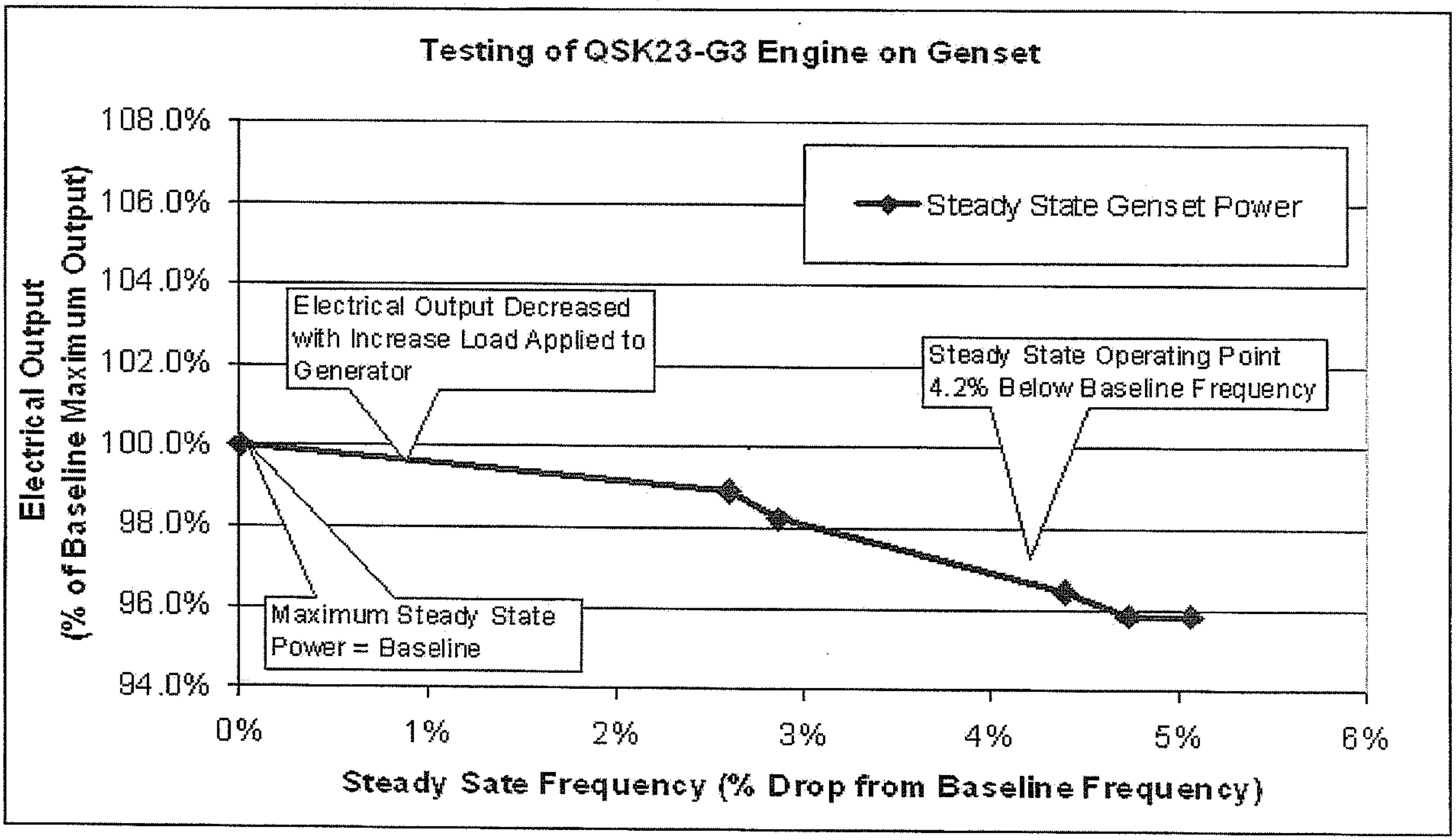
Engineering Evaluation SS-EV-98006, Rev. 9, defines the minimum performance requirements for CS-P-2B. In the post-LOP alignment, the charging pump will be providing normal charging and seal injection. SS-EV-98006 indicates that the minimum pump performance requirement at 120 gpm is 5320 feet of head. Degrading the pump shop curve, by 4.2% for speed, yields a performance of 139 gpm at 5415 feet. Therefore, there is no adverse impact on charging flows from the 4.2% underfrequency.

PCCW Pump

UFSAR Table 9.2-6 indicates that for normal operation, PCCW Train B design flow is 9747 gpm and flow for an extended (single train) cooldown is 7422 gpm. Actual PCCW flow is nominally 12,200 gpm (Table 1 of OS1012.04). Based upon these values, PCCW system flow is approximately 25% greater that the design requirement and the normal alignment requires 31% more flow than the extended cooldown alignment (i.e. the post-LOP alignment). Based upon these values, sufficient margin exists to ensure adequate flow with 4.2% underfrequency.

Prepared: C.I. Cronin Christine Cronin	Date: 9/22/09
Verified: T. A. Schulz for T. Schulz per telecon	Date: 9/22/09

Attachment E



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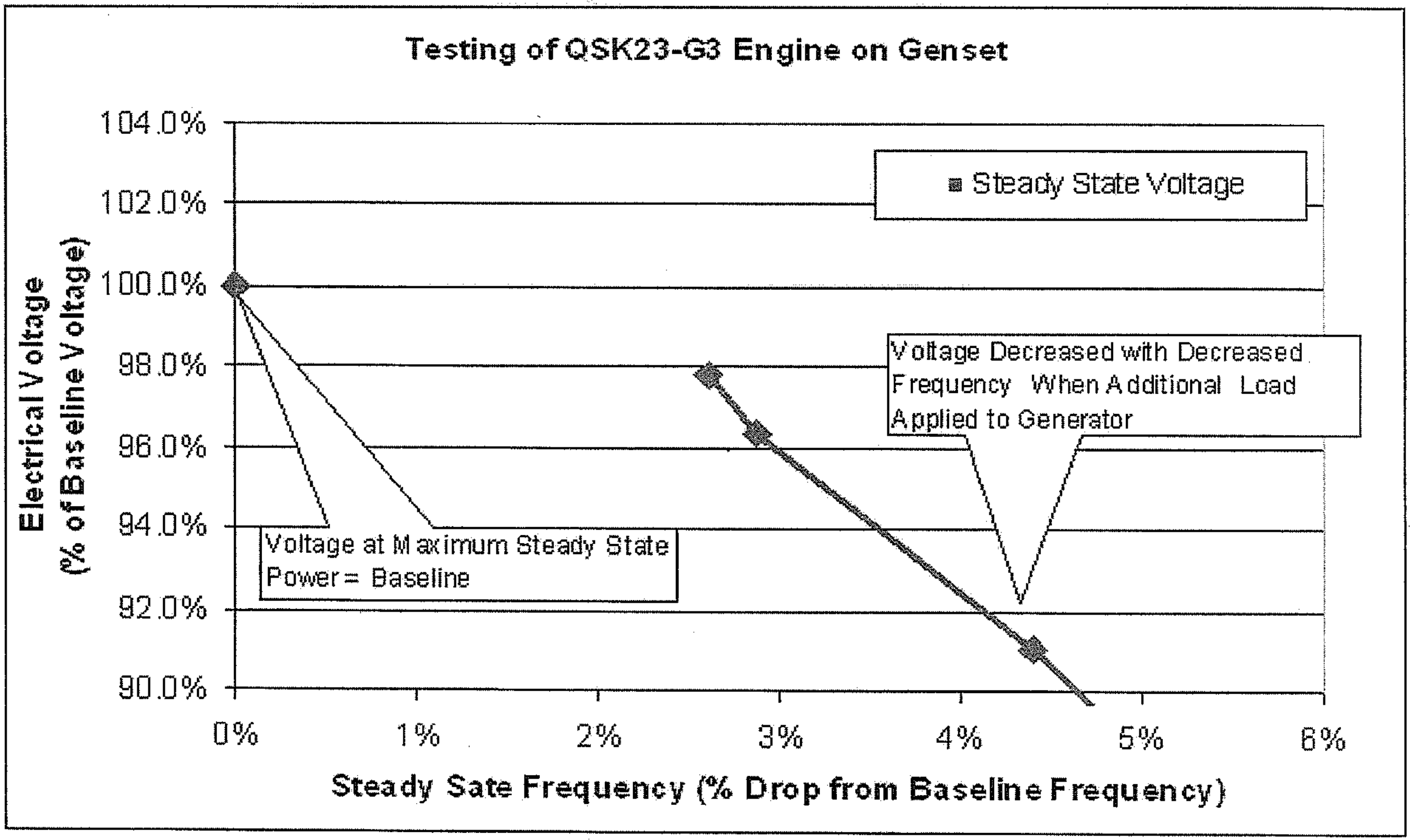

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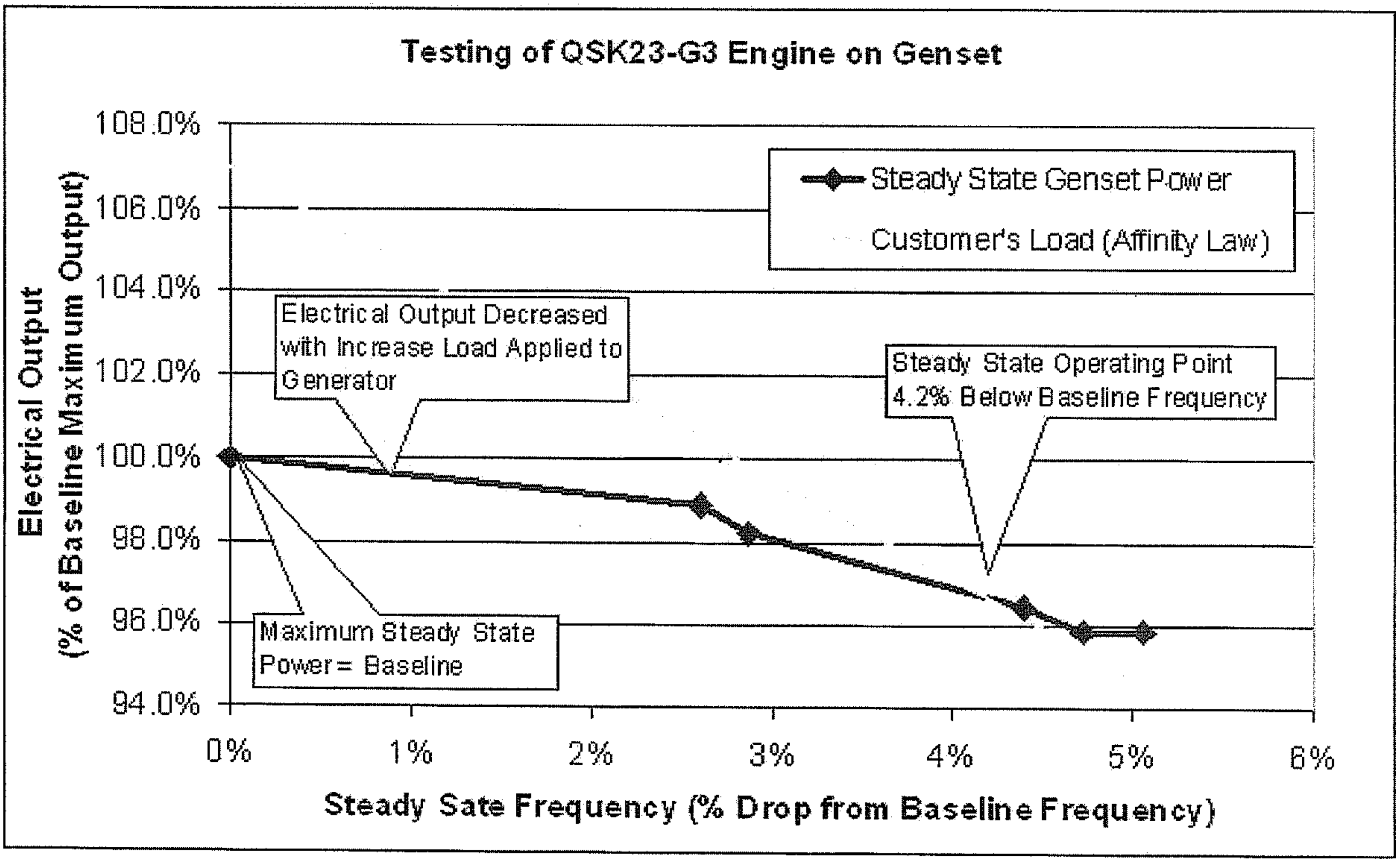

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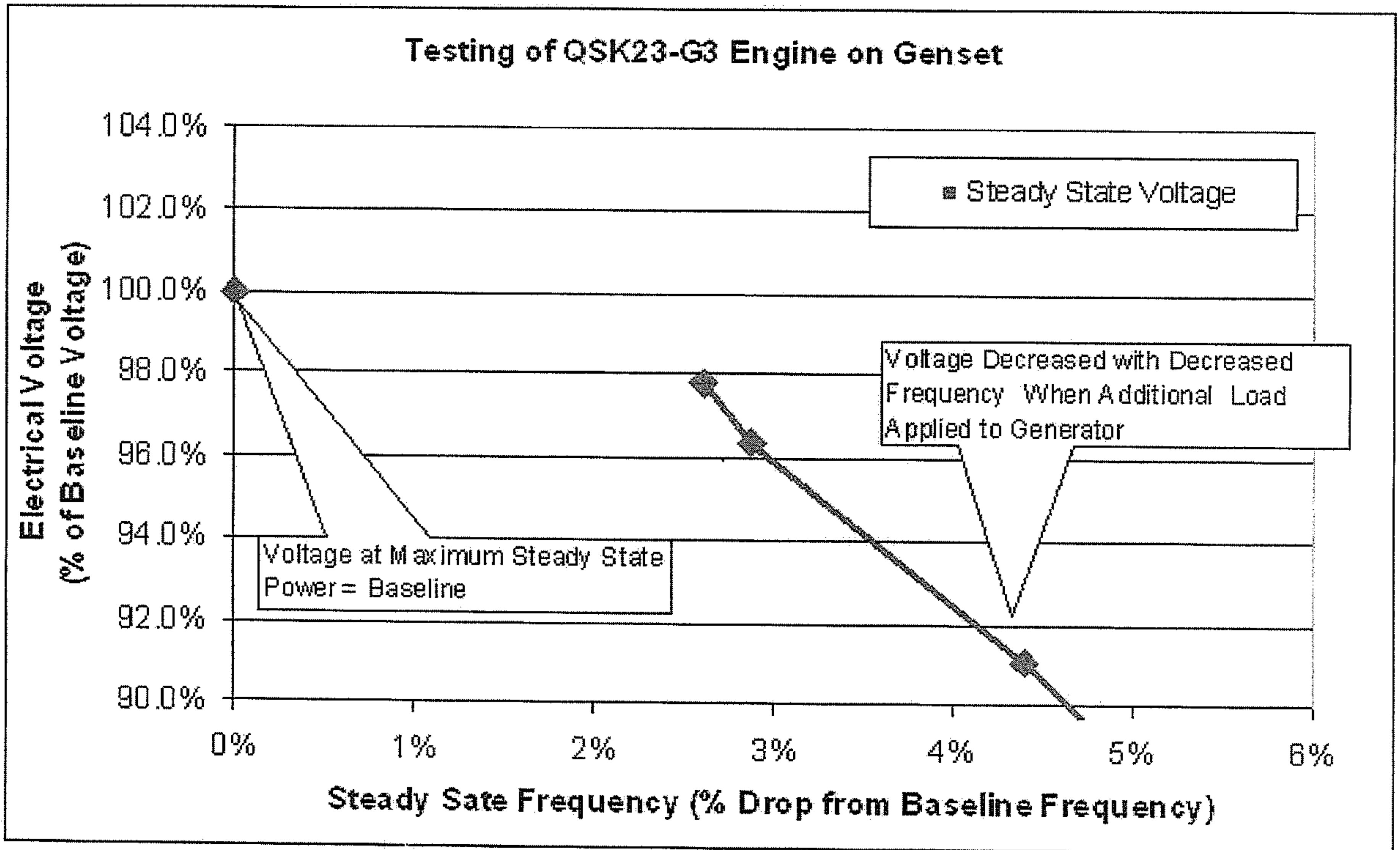

Attachment 2

Preliminary Presentation for Regulatory Conference

Seabrook Station Diesel Generator DG B Significance Determination

NRC Region 1
Regulatory Conference

September 30, 2009

Agenda

- Introduction – Gene St.Pierre
- Electrical Analysis – Rick Noble
- Risk Analysis – Ken Kiper
- Conclusions – Gene St.Pierre

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NextEra Team Members

Gene St.Pierre – Vice President North

Rick Noble – Engineering Site Director

Ed Metcalf – Operations Manager

Michael O'Keefe – Licensing Manager

Marjan Mashhadi – Senior Attorney

Ken Kiper – PRA Principal Engineer

Ken Letourneau – Electrical Principal Engineer

Gregg Sessler – Mechanical Principal Engineer

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Purpose

Address the risk significance of the DG B failure at Seabrook Station on Feb 25, 2009.

- NextEra Energy Seabrook concurs with the NRC determination that "NextEra's failure to adequately control design changes implemented on the DG B jacket water cooling system in January 2009 led to the failure of the gasket on flange JTR005 in the DG B jacket water cooling system on February 25."
- Electrical analysis demonstrates additional margin exists in the on-site AC power system (SEPS: Supplemental Emergency Power System).
- One of the two SEPS diesel generators can support LOOP loads based on actual running values.
- Risk analysis crediting this additional margin results in a risk significance of this event below 1E-6 (GREEN).

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DG B Failure Event 2/25/2009

EVENT

- 1/30/09 – During a planned Train B emergency diesel generator (DG B) maintenance outage, the "B" turbocharger cooling flange and gasket were assembled in accordance with a design change.
- 2/02/09 – DG B started 5 times for post maintenance testing, ran for ~10 total hrs.
- 2/25/09 – DG B failed during a surveillance test run. Specifically, the Jacket Water cooling system failed due to a gasket failure on the "B" turbocharger cooling flange. This failure occurred about 60 minutes after DG B started, when the DG had been loaded for about 30 minutes.
- 3/01/09 – DG B was functional after completion of repairs and comprehensive inspections.

UNAVAILABILITY TIME

- Total unavailability time (from 2/2/09 to 3/1/09) = 26.0 days = 0.0713 yr.
- Unavailability time includes the entire period between last successful run and completed repair. No degradation mechanism affected the component during the standby time period.

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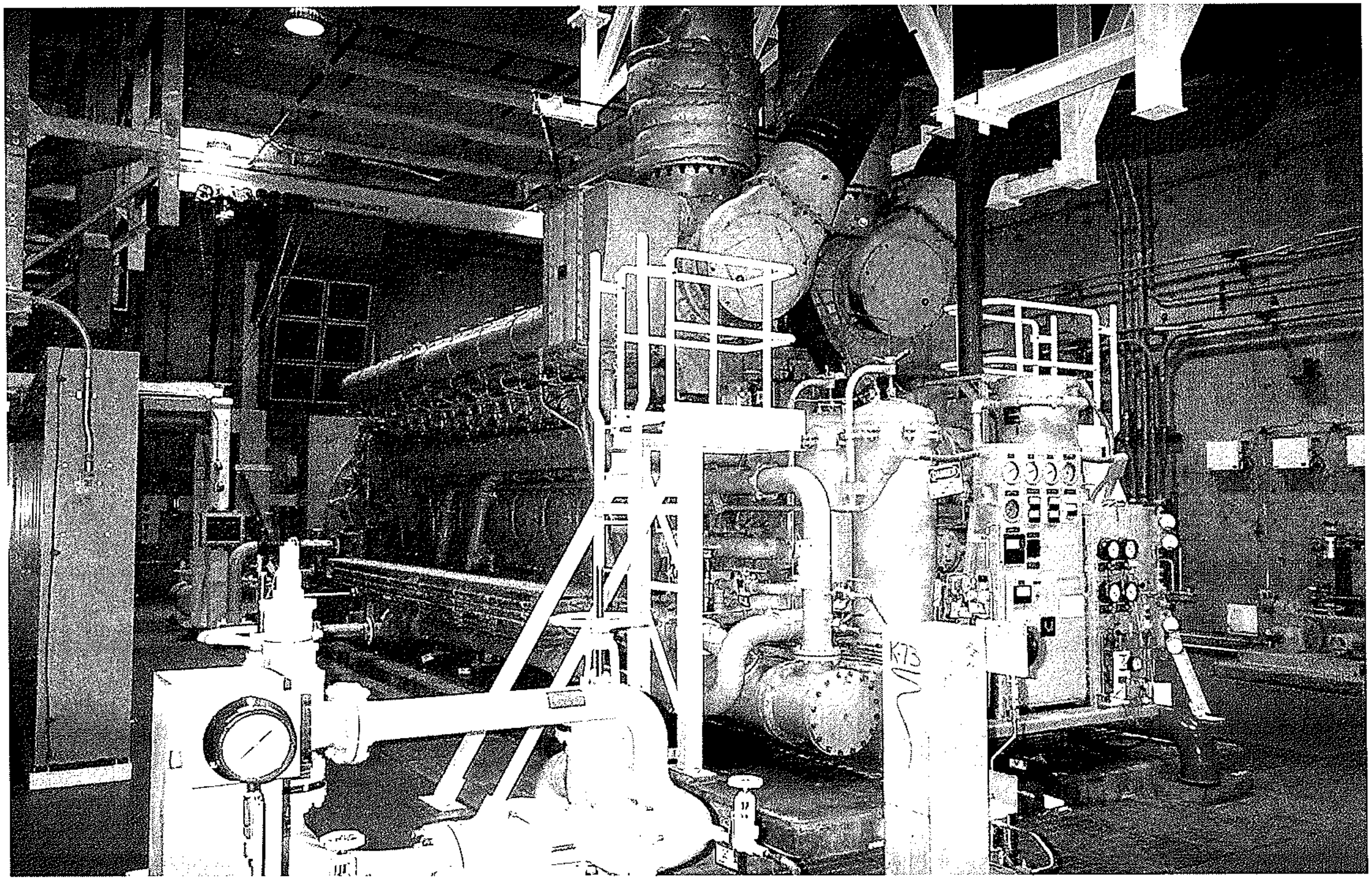
Emergency Diesel Generator B



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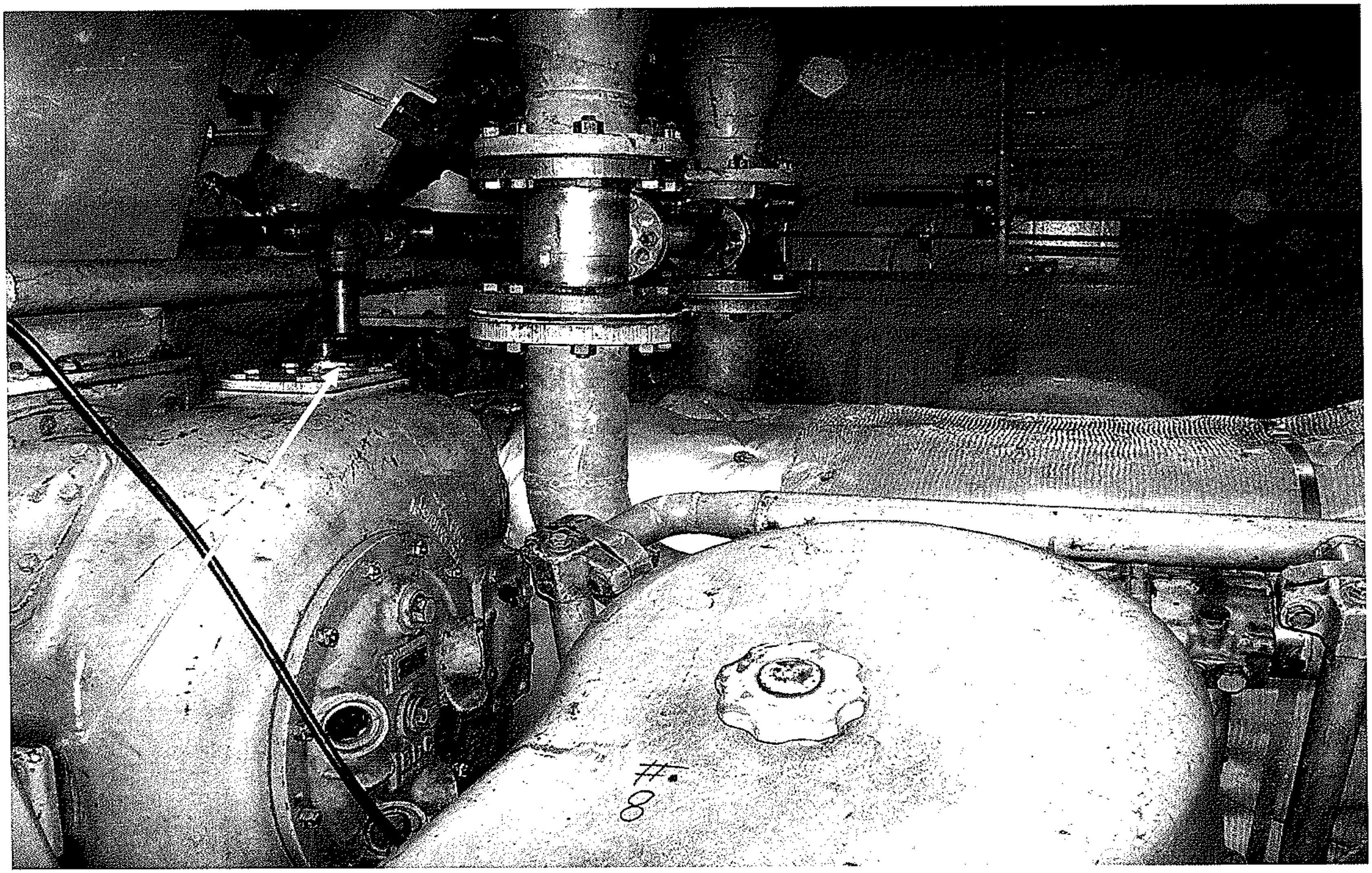
DG B Turbocharger and Coolant Piping



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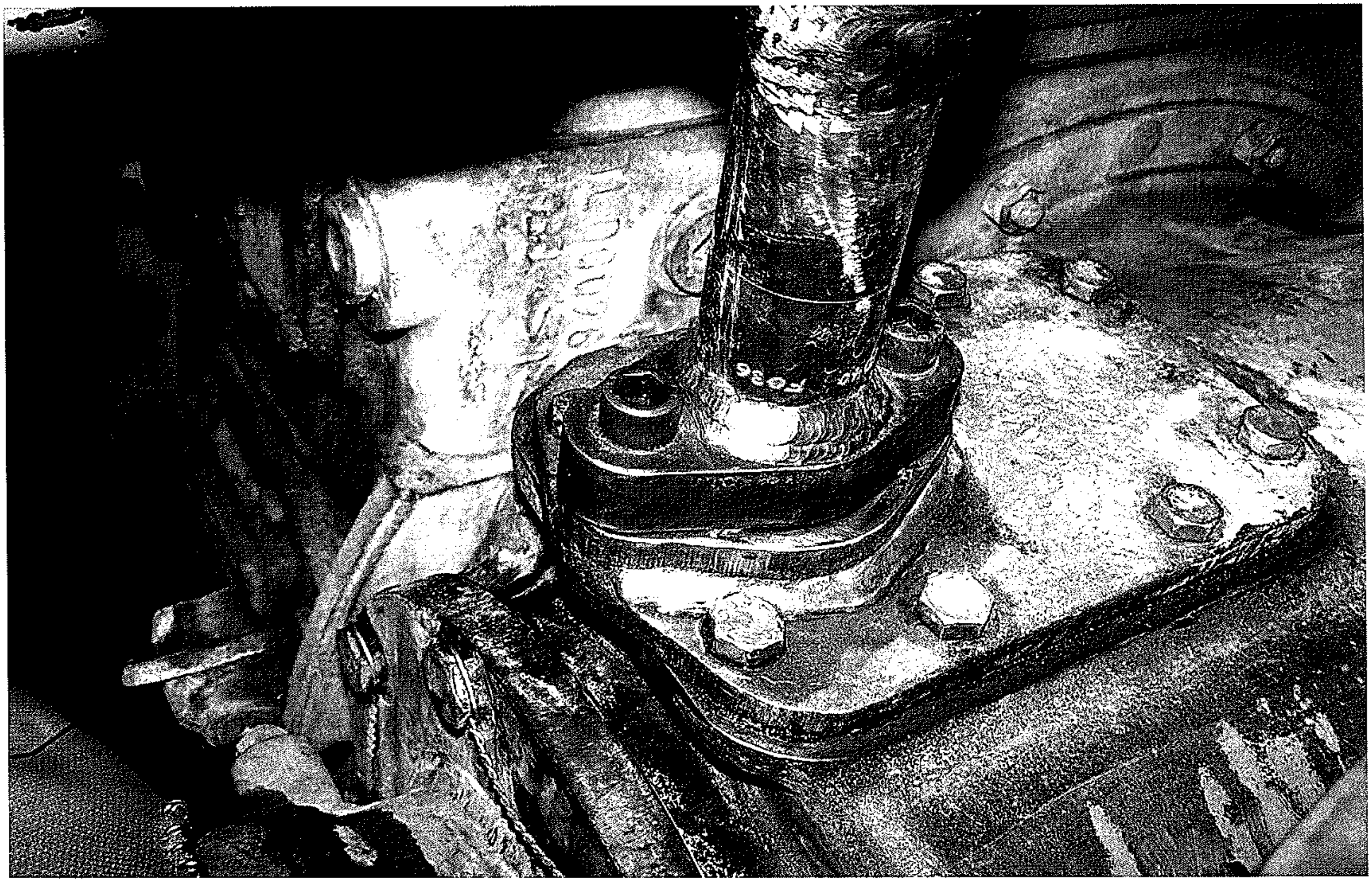
DG B Turbocharger Coolant Flange



Risk Assessment Indicates Green Significance

- Initially, NextEra Energy recognized that this event had the potential to be of low to moderate significance due to the importance of Emergency DGs and the duration of Emergency DG B unavailability

- During our evaluation of this event, NextEra Energy identified additional margin, inherent in the SEPS design, in the onsite AC power system that reduced the risk significance of this event to very low (green).

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SEPS Design

- SEPS supplies 4kV power to emergency buses E5 (Train A) or E6 (Train B) in the event of a loss of offsite power & failure of both Emergency DGs.
- SEPS supplies backup power to emergency buses when an Emergency DG is out of service for maintenance (14 day TS AOT).
- SEPS is permanently installed with two Cummins diesel generator sets (SEPS DGs) each nominally rated at 2700 kW, for a total SEPS capacity of 5400 kW.
- The SEPS Design LOOP Load of 4425 kW uses conservatively calculated values of LOOP loads plus additional conservatisms such as an RH pump is assumed to be running.

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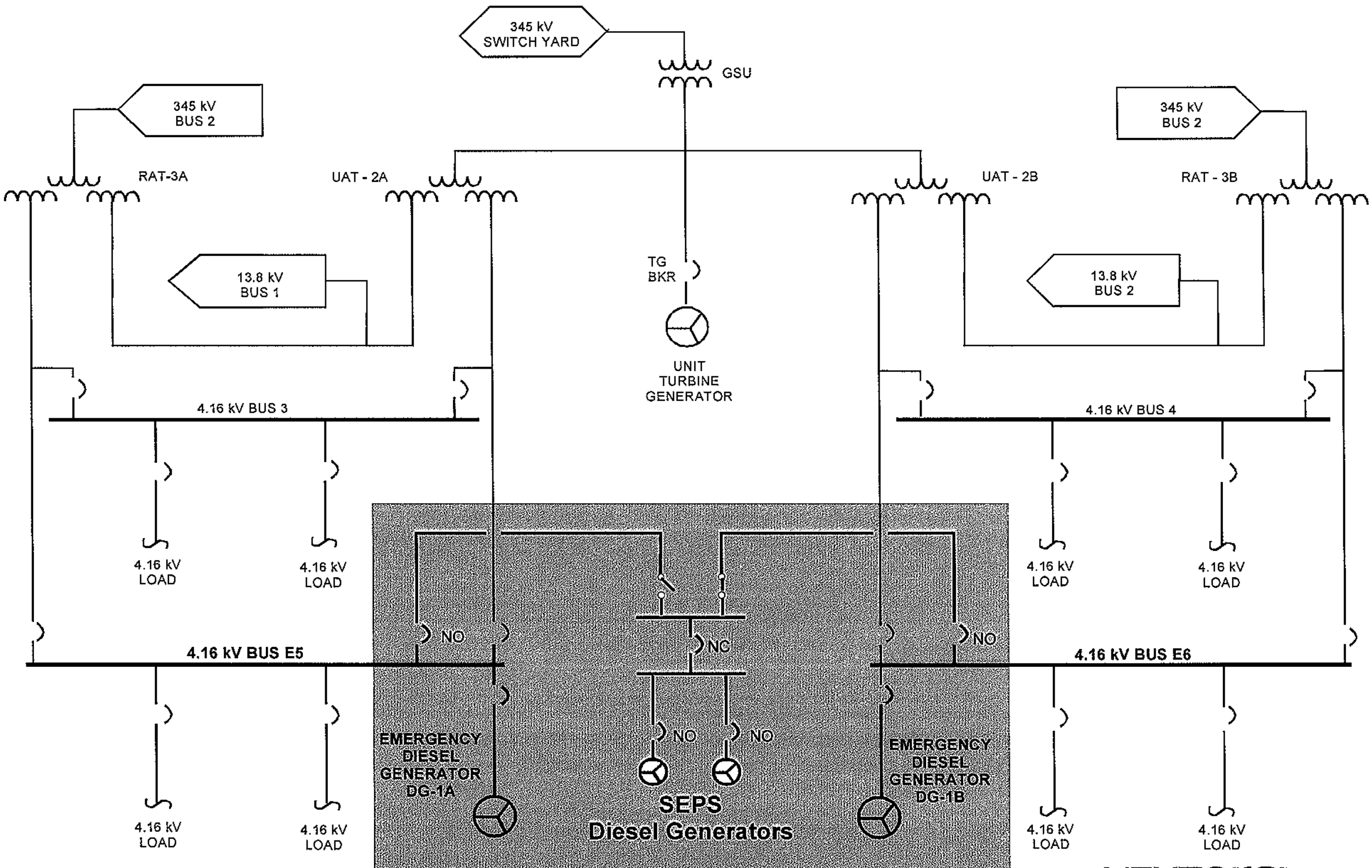
SEPS Design

- SEPS is normally aligned to Bus E6 due to motor-driven EFW pump powered from Bus E6.
- Auto starts on LOOP.
- Operator closes one breaker from the Control Room to connect SEPS to Bus E6, per procedure ECA-0.0, *Loss of All AC Power*.
- The Emergency Power Sequencer functions to connect loads to SEPS.

Electrical Design



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SEPS DGs and Switchgear

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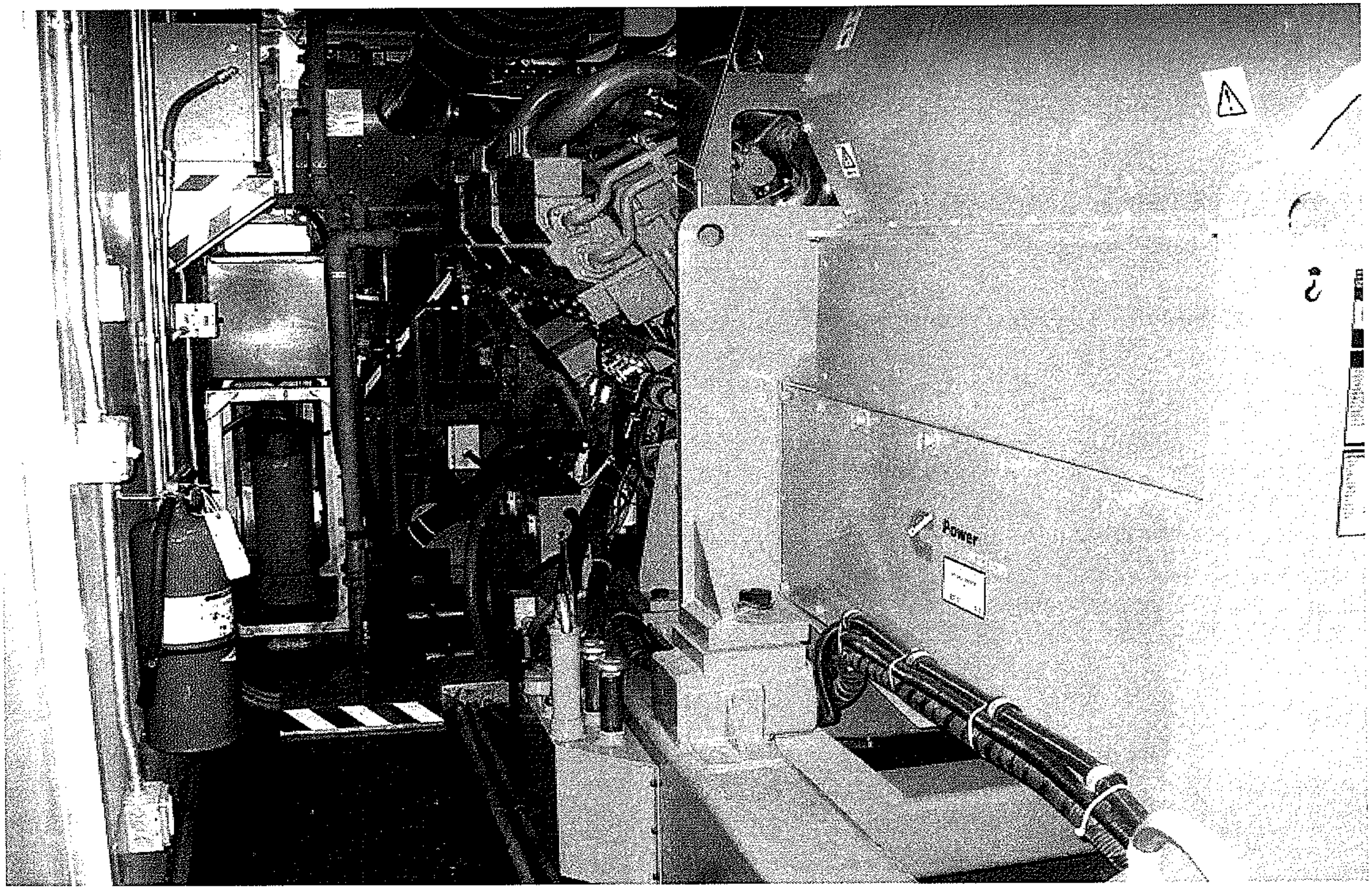
SEPS DG



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SEPS Margin Analysis

- Analysis determined that one of two SEPS DGs alone can support the LOOP loads based on actual running values.
- The single SEPS DG vendor Standby Rating of 2700 kW is based on its service application of supplying emergency power during a loss of all AC power.
- The Adjusted Base Rating is the standby rating adjusted to account for factory testing and improved efficiency due to engine break-in.

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SEPS Margin Analysis

- Single SEPS DG "Adjusted Base Rating" includes the following conservative considerations based on vendor information:
  - SEPS DG vendor Standby Rating: **2700 kW**
  - SEPS DG output based on extended load duration factory test: **+17 kW**
  - SEPS DG output adjusted for engine break in: **+27 kW**
  - SEPS DG Adjusted Base Rating:
    2700 kW + 17 kW + 27 kW = **2744 kW**
- The "Adjusted Base Rating" is **2744 kW.**

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SEPS Margin Analysis

- **The Adjusted Base Load is calculated to reflect the expected loading during a LOOP by adjusting the on-site commissioning test load value.**
- **The "Adjusted Base Load" of 2936 kW includes the following considerations:**
  - Loading based on the site commissioning test versus design calculated loads.
  - A nominal plant loading profile for the evaluated period of 2/02/09 to 3/01/09.
  - No Operator actions are required to reduce loads.
- **The Adjusted Base Load exceeds the single SEPS DG adjusted base rating at normal voltage and frequency.**
- **The 7% overloaded condition causes a slight reduction in frequency which in turn reduces the load demand below the SEPS DG Adjusted Base Rating.**

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SEPS DG Capability Above Adjusted Base Rating

- **Vendor testing demonstrated capability above the SEPS DG "Adjusted Base Rating."**
  - Testing performed on a smaller QSK series engine with the same cylinder design, same fuel system, same engine control system and generator control system, and similar air handling and base engine features as the SEPS DG QSK series engines.
  - Per the vendor, SEPS DG performance above the Adjusted Base Rating would be expected to provide similar results.
  - Loading above the Adjusted Base Rating results in reduced frequency & voltage.
  - Reduced frequency & voltage results in reduced power required by connected loads.

Equilibrium Reached at Lower Frequency

- **An equilibrium between load demand and supply is reached at a lower frequency.**
  - SEPS will stabilize at new equilibrium point; overcurrent protection setpoint is not reached.
  - The evaluation of connected loads showed acceptable design function performance at the equilibrium point.
    - -- All required pumps evaluated for changes in flow resulting from reduced frequency and determined to be capable of supplying required flow.
    - -- Effects of lower voltage evaluated on loads and protection devices and all would remain functional.
    - -- The impact on instrumentation, transformers, component protection and bus work would be insignificant.

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One SEPS DG Can Supply LOOP Loads

Conclusions:

- A single SEPS DG can supply the LOOP loads without tripping. The safe shutdown loads would perform their function at the reduced voltage & frequency values that would occur when operating a single SEPS DG above the Adjusted Base Rating.
- The SEPS system has additional defense-in-depth since one of two SEPS DGs is sufficient to power the Adjusted Base Load.
- No operator actions are required to reduce loads.

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Risk Assessment Results

Risk assessment using 1-of-2 SEPS DG success criteria shows risk <u>significantly below</u> 1E-6 (GREEN).

Description	DG B Status	SEPS Model	CDF123 (CASE X)	dCDF	Unavailability Time (yrs)	ICDP
NEW BASECASE: SB2009X Average Maintenance, Modes 1 to 3 -AND- Single SEPS Success Criteria	available	*1-of-2 required*	1.02E-05			
				8.62E-06	0.0713	**6.14E-07**
NEW BASECASE AND DG B out of service	*out of service*	*1-of-2 required*	1.88E-05			

dCDF: delta core damage frequency

ICDP: incremental core damage probability

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Seabrook PRA

- **Seabrook PRA Risk Model used for SDP**
  - Analyzed initiators: internal events, internal flood, internal fire, seismic events
  - Modes 1 to 3: at power, low power, hot standby
  - Average test & maintenance unavailability
  - Revised in June 2009 to account for latest plant design, procedures, & data (periodic update)
  - Meets Cat 2 of ASME/ANS PRA Standard (RG1.200 Rev 1) with minor exceptions
- **Risk significance of this event was evaluated using a full scope analysis with detailed plant-specific modeling.**

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PRA Station Blackout Model

OFFSITE POWER

- LOOP initiators considered: plant-centered (LOSPP), grid-centered (LOSPG), weather-related (LOSPW), quantified based on generic data from NUREG/CR-6890, updated with plant-specific data.
- Consequential LOOP is modeled for all other initiators, to account for the potential for LOOP resulting from the plant trip.
- Offsite power recovery curves are modeled using generic data from NUREG/CR-6890.

EMERGENCY DGs

- Detailed fault tree systems analysis for DG A & DG B, including test & maintenance unavailability & common cause failure
- System model uses 24-hour mission time for weather-related LOSP sequences; 6-hour mission time for all other LOSP sequences.
- DG A and DG B failure rates are based on generic data from NUREG/CR-6928, updated with plant-specific data.
- DG recovery is modeled using plant-specific data (0.45 non-recovery probability for sequences with at least 4-hours recovery time available).

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PRA Station Blackout Model

SEPS

- Detailed fault tree systems analysis for SEPS, includes test & maintenance unavailability & common cause failure.
- SEPS failure rates are based on generic data from NUREG/CR-6928.
- Revised model consists of two SEPS DGs which are modeled with a 2-of-2 success criteria for LOOP/SI sequences and a 1-of-2 success criteria for LOOP/non-SI sequences.

TURBINE-DRIVEN EFW PUMP

- AC power independent, continues to run as long as DC power is available.
- When DC batteries are eventually drained on a SBO sequence, the model assumes the TD EFW pump fails.

OTHER

- Vital DC batteries are modeled to operate for a nominal time period of 4 hours, or for an extended time of 12 hours based on procedural-directed load shedding.
- RCP seal leakage model: for an extended SBO, the RCP seals are modeled to leak at each of three potential leakrates: 84 gpm, 728 gpm, or 1920 gpm, based on the standard Westinghouse model.

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Additional PRA Considerations

1. **Operator Actions Related to SEPS**
2. **Fail-to-Run Single SEPS DG Scenario**
3. **Nominal Plant Model Assumptions**

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(1) Operator Actions re SEPS

- SEPS auto starts on loss of offsite power (no action required).
- Initial operator action in response to a loss of all AC power, per emergency procedure ECA-0.0, *Loss of All AC Power:*

ECA-0.0 Step 5b

b. Manually start emergency diesel generator(s) from the main control room:

- Emergency start
- Slave relay K603 test switch S909

Step 5b RNO

b. Perform the following:

- IF SEPS bus feeder breaker is aligned to Bus 6, THEN:

  1) Place the following equipment control switches in PULL TO LOCK position:
     - DG 1B output breaker
     - CBS-P-9B
     - SI-P-6B

  2) Manually close SEPS Bus 6 breaker. IF breaker will NOT close, THEN go to Step 6.

- The Emergency Power Sequencer automatically starts the required loads.

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(1) Operator Actions re SEPS

- Subsequent steps address load management. Note: no operator actions are required to reduce SEPS load.

ECA-0.0 Step 5j

j. Check emergency bus – POWERED BY EMERGENCY DIESEL

Step 5j RNO

j. IF emergency bus is powered by SEPS, THEN maintain SEPS load limit per ATTACHMENT A while performing actions in other procedures in effect.

ATTACHMENT A

SEPS LOAD LIMIT GUIDANCE

1 Dispatch operator to locally determine SEPS load condition and number of diesels running:

- Verify SEPS load with two diesels running – LESS THAN 5280 KW

  - OR -

- Verify SEPS load with one diesel running – LESS THAN 2640 KW

2 Determine pump start load limit from table below prior to starting pumps:

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(1) Operator Actions for SEPS

Operator Actions Conclusions:

- SEPS auto starts - no operator action required.
- Simple operator actions from control room to close the SEPS breaker to the emergency bus.
- Emergency sequencer automatically starts essential loads - no operator action required.
- No operator actions are required to reduce SEPS load. Any SEPS load management would occur in the longer term in consultation with TSC staff.
- The PRA models the critical steps needed to close SEPS breaker. These actions are independent of whether 1 or 2 SEPS DGs are operating.

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(2) SEPS Fail-to-Run Scenario – Not Significant

- SEPS electrical margin analysis is based on a single SEPS DG being available at the beginning of the scenario (i.e., the second SEPS DG fails to start).
- If both SEPS DGs initially start, the load on Bus E6 may exceed the max load capacity for one SEPS DG as additional loads that are added by procedure.
- If one SEPS DG fails to continue to run, the remaining SEPS DG could trip off on overload.

(2) SEPS Fail-to-Run Scenario – Not Significant

- **Low Frequency Scenario**
  - Based upon the SEPS system analysis, the most likely failure scenario for SEPS is at time zero (maintenance unavailability or fail-to-start).
    - -- The time-zero failure modes account for the vast majority of SEPS unavailability: 97% for 6 hr mission time; 84% for 24 hr mission time.
  - Thus, the fail-to-run scenario is a low frequency scenario.
- **Procedural Path**
  - Given the fail-to-run scenario with both SEPS DGs tripping off, operators would re-enter ECA-0.0 and at Step 8 restart a single SEPS DG.
  - Operators would start required loads from the Control Room as directed by the Emergency Operating Procedures.
  - While this procedure path requires more operator actions, there is also more time available due to the decay heat removed while both SEPS DGs operated.

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(2) SEPS Fail-to-Run Scenario – Not Significant

- **Conclusions:**
  - Electrical analysis is based on fail-to-start loading.
  - SEPS DG fail-to-run scenario is low frequency compared to the fail-to-start scenario.
  - EOPs handle SEPS restart & loading required for fail-to-run scenario as well as fail-to-start scenario.
  - Based on PRA sensitivity analysis, SEPS DG fail-to-run scenario is not significant to the conclusion that risk <1E-6.

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(3) Nominal PRA Model

- **SDP guidance requires use of the "nominal" PRA model.**
- **Electrical analysis is based on a "nominal plant." This includes assumptions of two system alignments critical to SEPS loading:**
  - RHR Pump
    - -- Electrical analysis assumes the RHR pumps are in standby, and thus, would not auto start given a LOOP.
    - -- The nominal PRA model in Mode 1 – 3 includes RHR pumps in standby.
    - -- If a LOOP occurred in the short period of time when a RHR pump was running in test, the emergency sequencer would restart the RHR pump – a large, additional load.
  - SW System
    - Electrical analysis assumes the SW System is aligned to the ocean, and thus, ocean SW pumps (not cooling tower pumps) would auto start given a LOOP.
    - PRA model includes both ocean & cooling tower SW System alignment.
    - The nominal PRA model is with the SW System aligned to the ocean. SW Train B is historically aligned to the cooling tower < 1% of the time.
    - If a LOOP occurred in the short period of time when a SW Train was aligned to the cooling tower, the SW cooling tower pump would restart – a larger load than the ocean SW pump.

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(3) Nominal PRA Model

- **Low Frequency Scenarios**
  - Both the RH and SW off-normal alignments occur for brief periods of time and do not represent the nominal model
  - The electrical analysis does not include these off-normal alignment loads.
  - These alignments are not explicitly included in the PRA model with regard to the 1-of-2 SEPS DG success criteria.
- **Based on PRA sensitivity analysis, these overload scenarios are not significant to the conclusion that risk is <1E-6.**

PRA Sensitivity Analysis

- **Conservative assumption:**
  - The *1-of-2 SEPS DG success criteria* does not apply for 10% of the exposure time.
- **Calculation:**

ICDP = dCDF(1-of-2 SEPS) x T_{EXP} x 0.90 + dCDF(2-of-2 SEPS) x T_{EXP} x 0.10

= $\underline{8.62E\text{-}06 \times 0.0713 \times 0.90}$ + $\underline{1.71E\text{-}05 \times 0.0713 \times 0.10}$

= $\underline{6.14E\text{-}07 \times 0.90}$ + $\underline{1.22E\text{-}06 \times 0.10}$ = **6.75E-07**

- **Conclusions:**
  - ICDP (sensitivity case) = 6.75E-7
  - ICDP is still well below 1E-6 (GREEN) even when using a conservative success assumption.

Exposure Time = Unavailability Time(DG B):

T_{EXP} = 0.0713 yrs

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Uncredited Additional Electrical Margin

(1) Peak Load

- The Seabrook Station electrical analysis uses the "adjusted base load" (2936 kW) which is based on actual loading during the SEPS test, adjusted for expected load values.
- However, the average (nominal) load during the month of Feb 2009 was ~2800 kW. This is additional margin over the load analyzed.

(2) Instrument Uncertainty

- The electrical analysis included ~1% additional load to account for instrument uncertainty.
- Since there is no reason to expect instruments to be biased plus or minus, this is additional margin in this analysis.

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Uncredited Additional PRA Margin

(3) DG B Recoverability

- The basecase PRA model includes modest credit for Emergency DG recovery based on plant-specific experience over the life of the plant.
- Based on discussions with maintenance & operations, the February 25, 2009 DG B failure would have been recoverable within 2 to 4 hours since it was simple to diagnose and the failure was the gasket of a relatively easy to replace two-bolt flange.
- This additional recovery credit is not included in the quantitative results.

(4) Time of DG B Failure

- The DG B failure on February 25, 2009 occurred after about 1 hour run time.
- The time available for recovery assumes the SBO (loss of offsite power & all Emergency DGs fail) at time zero. If an Emergency DG runs successfully for some time, these recovery times will extend due to: (a) reduced decay heat when the SBO occurred, at 1 hour after shutdown and (b) the offsite power recovery which would have begun at the time of loss of offsite power, before the SBO time begins.
- This additional recovery credit is not included in the quantitative results.

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Risk Assessment Indicates Green Significance

Overall Conclusions

1. SEPS capacity (1-of-2 SEPS DG success criteria) is supported by detailed analysis and vendor test data.
2. Electrical analysis & risk analysis include additional margin.
3. With 1-of-2 SEPS DG success criteria, risk from Feb 2009 DG B failure is GREEN (calculated as 6.14E-7).

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