NEXTera ENERGY
POINT BEACH

September 25, 2009

NRC 2009-0098
10 CFR 50.90

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555

Point Beach Nuclear Plant, Units 1 and 2
Dockets 50-266 and 50-301
Renewed License Nos. DPR-24 and DPR-27

License Amendment Request 261
Extended Power Uprate
Response to Request for Additional Information

References:
(1) FPL Energy Point Beach, LLC letter to NRC, dated April 7, 2009, License Amendment Request 261, Extended Power Uprate (ML091250564)
(2) NRC letter to NextEra Energy Point Beach, LLC, dated August 26, 2009, Point Beach Nuclear Plant, Units 1 and 2 – Request for Additional Information from Electrical Engineering Branch Regarding Auxiliary Feedwater (TAC Numbers ME1081 and ME1082) (ML092310454)

NextEra Energy Point Beach, LLC (NextEra) submitted License Amendment Request (LAR) 261 (Reference 1) to the NRC pursuant to 10 CFR 50.90. The proposed license amendment would increase each unit's licensed thermal power level from 1540 megawatts thermal (MWt) to 1800 MWt, and revise the Technical Specifications to support operation at the increased thermal power level.

Via Reference (2), the NRC staff determined that additional information was required to enable the staff's continued review of the request. Enclosure 1 provides the NextEra response to the NRC staff's request for additional information. Enclosures 2 through 9 provide additional information in support of NextEra's response to specific questions.

This letter contains no new Regulatory Commitments and no revisions to existing Regulatory Commitments.

The information contained in this letter does not alter the no significant hazards consideration contained in Reference (1) and continues to satisfy the criteria of 10 CFR 51.22 for categorical exclusion from the requirements of an environmental assessment.

A001
NRR

In accordance with 10 CFR 50.91, a copy of this letter is being provided to the designated Wisconsin Official.

I declare under penalty of perjury that the foregoing is true and correct.
Executed on September 25, 2009.

Very truly yours,

NextEra Energy Point Beach, LLC

FOR

Larry Meyer
Site Vice President

Enclosures

cc: Administrator, Region III, USNRC
Project Manager, Point Beach Nuclear Plant, USNRC
Resident Inspector, Point Beach Nuclear Plant, USNRC
PSCW

ENCLOSURE 1

NEXTERA ENERGY POINT BEACH, LLC
POINT BEACH NUCLEAR PLANT, UNITS 1 AND 2

LICENSE AMENDMENT REQUEST 261
EXTENDED POWER UPRATE
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION

The NRC staff determined that additional information was required (Reference 1) to enable the Electrical Engineering Branch to complete its review of the auxiliary feedwater system portion of License Amendment Request (LAR) 261, Extended Power Uprate EPU (Reference 2). The following information is provided by NextEra Energy Point Beach, LLC (NextEra) in response to the NRC staff's request.

Question 1

The licensee stated that resulting worst-case calculated transient voltage dip is approximately 48 percent during the start of the motor driven auxiliary feedwater (MDAFW) pump at the time of emergency diesel generator (EDG) breaker closure. The staff notes that this voltage dip is well below the acceptance limit of 75 percent of nominal voltage during a motor start from the EDG. Please provide documentation (test data and transient analyses) to demonstrate that all loads (worst-case accident loads) can be sequenced successfully while maintaining the voltage and frequency within its design limits.

NextEra Response

The requirements listed in Question 1 are based on Regulatory Guide (RG) 1.9, Revision 4, Application and Testing of Safety-Related Diesel Generators in Nuclear Power Plants, (Reference 3). Although NextEra is not committed to RG 1.9 in the PBNP current licensing basis, the following discussion is provided to address the acceptability of the PBNP design.

Dynamic loading calculations for each emergency diesel generator (EDG) demonstrate that the EDGs are capable of performing their specified safety function and that all loads will be successfully sequenced with acceptable voltage and frequency values. The EDG dynamic loading calculation provides the link between the Technical Specification (TS) Surveillance Requirement (SR) 3.8.1.5 and the design basis accident loading. This is accomplished by first developing a dynamic computer model of each EDG and comparing the response of the EDG voltage and frequency during testing. The EDG dynamic computer model is tuned to match the tested response in a conservative manner. EDG dynamic loading analysis is then performed for the design basis condition.

An engineering evaluation has been completed which demonstrates that the EDGs are capable of successfully sequencing all required electrical loads for the maximum design basis loading on the EDGs, including the loads from the upgraded auxiliary feedwater (AFW) system and alternative source term (AST) modifications. The calculation discussed above and evaluation demonstrate that the EDGs are capable of starting and accelerating all safeguards loads to rated speed within the time requirements of the accident analysis and the EDGs recover back to nominal voltage and frequency. The calculation and evaluation show that the Train B EDGs remain above 75% of nominal voltage throughout the motor starting sequence in all cases. The Train A EDGs voltage will dip to approximately 48% of nominal voltage during the AFW pump motor start. The evaluation and calculation also show that this voltage dip will not impact the capability of the EDGs and safeguards loads from performing their specified safety function. The evaluation demonstrates that voltage recovers to acceptable levels (within ±5% of 97.5% of nominal voltage) prior to a start of a subsequent motor.

The minimum voltage on the Train A EDGs will dip to approximately 48% of the nominal voltage. The voltage regulator for Train A EDGs is an analog magnetic amplifier design utilizing power current transformers (CT) that vectorally adds the high reactive current during a motor start to boost the excitation current and voltage. The voltage dips are transient in nature and rapidly recover to within ±5% of 97.5% of nominal voltage. As a result, the significant initial voltage dip does not challenge the voltage regulator system, nor cause it to operate in a different discrete region (i.e., excitation dependency on other components) other than for what it is designed. The very rapid voltage recovery exhibited during testing indicates sufficient margin remains in the excitation system to rapidly recover generator terminal voltage and complete the starting of each of the automatically connected loads. The calculation and evaluation confirm that the Train A EDGs are capable of performing their designated safety function and all loads will be successfully sequenced with acceptable voltage values.

The following information is provided in Enclosure 2:

- EDG voltage and frequency plots from engineered safeguards test performed during the fall 2008 Unit 1 Refueling Outage 31 (U1R31)
- EDG voltage and frequency profiles from the transient loading analysis
- EDG voltage and frequency profiles from the evaluation of the impact on EDG transient loading analysis resulting from the AFW and AST modifications

The test data, calculation and engineering evaluation demonstrate that the EDGs are capable of starting safeguards loads and the voltage recovers quickly to the acceptable voltage level.

Question 2

The licensee stated that the transient frequency response of all four EDGs remains above 57 hertz (Hz) at all times. Provide documentation to show that, during sequencing, the EDG frequency will be restored to within 2 percent of nominal in less than 60 percent of each load-sequence interval for step load increase and in less than 80 percent of each load sequence interval for disconnection of the single largest load. Also, describe how the effects of frequency variations have been evaluated to satisfy the design bases for emergency core cooling system loads and vital loads, including EDG loading.

NextEra Response

The requirements listed in Question 2 are based on RG 1.9, Revision 4 (Reference 3). Although PBNP is not committed to RG 1.9 in our current licensing basis, the following discussion is provided to address the acceptability of the PBNP design.

An engineering evaluation and calculation have been completed to demonstrate that the EDGs are capable of successfully sequencing the loads. The evaluation considered the electrical loads associated with the AFW and AST modifications and their effect on the EDG dynamic loading calculation results. The engineering evaluation and calculation demonstrate that the EDG frequency is less than +2% of nominal. In two instances the frequency is less than -2% of nominal for a maximum of 0.5 seconds. This is less than 60% of the time between load sequence intervals, which are 5 or 3 seconds.

The dynamic response effect of frequency on equipment in the electrical distribution system is taken into account by the electrical transient and analysis program (ETAP) software utilized to perform the calculation. The maximum allowable steady-state frequency variation on equipment powered by the EDG is evaluated within EDG steady-state loading analysis. Only rotating equipment (fans and pumps) are affected by frequency on bus loading. For conservatism, PBNP applies a demand factor to all constant KVA loads (including motors) to increase the load by an equivalent value related to the maximum allowable steady-state frequency.

Disconnection of the single largest load is not required by PBNP TS and testing of this attribute is not performed.

The following information is provided in Enclosure 2:

- EDG voltage and frequency plots from engineered safeguards test performed during U1R31
- EDG voltage and frequency profiles from the transient loading analysis
- EDG voltage and frequency profiles from the evaluation of the impact on EDG transient loading analysis resulting from the AFW and AST modifications

The test data, calculation and engineering evaluation demonstrate that the EDGs are capable of starting safeguards loads and frequency recovers quickly to the acceptable range.

Question 3

Since auxiliary feedwater pump cables are routed thru duct banks, explain the design features provided to prevent submergence of cables and periodic testing to be performed to monitor the condition of the cables.

NextEra Response

Power to the new motor-driven AFW Pump 1P-53 motor from Train B EDGs will be routed through duct banks. Power to the new motor-driven AFW pump 2P-53 motor from Train A EDGs will be routed through the control building and primary auxiliary building (PAB) and will not be subjected to potential submergence.

The duct banks are underground reinforced concrete structures that encase galvanized steel and polyvinyl chloride (PVC) pipes, which serve as conduits for electrical cables. The duct banks are constructed with a slope to allow potential ground water intrusion to flow to manholes. Routine monitoring is performed for the manholes to detect water accumulation and to pump out accumulated water. Weekly and monthly monitoring includes manhole inspections for water, documentation of water level, documenting if cables are found under water and pumping out the manhole.

The motor-driven auxiliary feedwater (MDAFW) pump motor cables will be included in the cable condition monitoring program. The cable condition monitoring program manages aging of conductor insulation materials on cables and connectors, and other electrical insulation materials that are installed in adverse localized environments caused by heat, radiation or moisture. The scope of this program includes accessible non-EQ electrical cables and connections, including control and instrumentation circuit cables, non-EQ electrical cables used in nuclear instrumentation circuits, and inaccessible non-EQ medium-voltage cables within the scope of license renewal. The program requires (a) visual inspection of a representative sample of accessible electrical cables and connections in adverse localized environments once every 10 years for evidence of jacket surface degradation, (b) testing of nuclear instrumentation circuits once every 10 years to detect a significant reduction in cable insulation resistance, and (c) testing of a representative sample of in-scope, medium-voltage cables not designed for submergence subject to significant moisture and significant voltage once every 10 years to detect deterioration of insulation. Cables routed through duct banks for MDAFW pump 1P-53 motor will be subject to the cable condition monitoring program.

Question 4

Describe the environmental parameters for the MDAFW pump motor locations. Are the MDAFW pump motors located in a room that is susceptible to a high energy line break or harsh environment? Are the MDAFW pump motors required to be qualified in accordance with 10 CFR 50.49 requirements? If not, provide the basis.

NextEra Response

Environmental parameters for the new MDAFW pump motor locations are as follows:

- Temperature
  - The normal PAB maximum temperature is 85°F.
  - Maximum temperature is less than 130°F.
  - The PAB Elevation 8' location of MDAFW pump motors is not subject to high energy line break (HELB) temperatures.
- Pressure
  - The normal PAB pressure is slightly less than atmospheric.
  - The PAB Elevation 8' location of MDAFW pump motors is not subject to HELB pressurization.
- Radiation
  - The normal radiation level is 1300 RAD for 60-year total integrated dose (TID).
  - The abnormal radiation level in MDAFW pumps rooms due to chemical and volume control system (CVCS) demineralizer flushing operations is less than 20-30 mRem/hr at the floor level. The elevated dose rates for this evolution exist for approximately ten hours per year.
  - The MDAFW pumps are not required to operate during the emergency core cooling system (ECCS) recirculation phase of a loss of coolant accident (LOCA). Therefore, they do not need to be qualified for post-LOCA harsh radiation levels on PAB Elevation 8'.

The MDAFW pumps and associated equipment will not be included in the 10 CFR 50.49 program, Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants, because they will not require qualification for harsh environments. The MDAFW pump motor locations will not be subjected to adverse conditions resulting from a HELB. Radiation levels in the area during post-LOCA conditions could be harsh; however, the MDAFW pumps are not required for response to this accident. Therefore, they do not need to be qualified for the post-LOCA radiation levels.

Question 5

In response to the staff's acceptance review question number 7, regarding changes to the time delay relays for 4.16 kilo-Volt (kV) and 480 Volt (V) loss-of-voltage (LOV) relays and the EDG breaker close delay relay, the licensee stated that the acceptance criteria is satisfied since the total calculated time is 13.3 seconds, which is less than the acceptance criteria of 14 seconds. The licensee also stated that this time bounds the delay time from initiation of the LOV signal to closure of the EDG output breaker assumed in the Point Beach Nuclear Plant accident analysis. However, the staff notes that this time (14 seconds) is inconsistent with the EDG design basis provided in Section 8.8.1 of the Point Beach Nuclear Plant's Final Safety Analysis Report (FSAR) which states that the EDGs are required to start and be ready for loading within 10 seconds after receiving a start signal. The staff was unable to confirm the design bases requirement for the 14-second acceptance criteria that was referenced in the licensee's response. Provide the basis for the changes to the time delay relays for the 4.16 kV and 480 V LOV relays and the EDG breaker close delay relay.

NextEra Response

Final Safety Analysis Report (FSAR) Section 8.8.1, Diesel Generator System Design Basis, states the EDGs are required to start and be ready for loading within 10 seconds after receiving a start signal. This is a criterion for the EDG and is not affected by EPU. The EDGs remain capable of starting and being ready to load within 10 seconds of a start signal.

The accident analysis time delays are based on the EDGs powering the bus within 14 seconds to support the timing requirements for safety related loads. The 14 seconds is included within the total time requirements of the accident analysis for low head safety injection (LHSI), high head safety injection (HHSI), and containment spray and containment fan coolers when a loss of offsite power (LOOP) is considered. The acceptance criteria take into consideration the degraded voltage logic, loss of voltage logic and EDG ready to load. Since the EDGs are capable of supplying power to the safeguards buses within 14 seconds, the accident analysis assumptions remain satisfied.

Question 6

Provide the supporting documentation that was used in developing your response to questions 1-7 of the staff's acceptance review. At a minimum, the supporting documentation must include the assumptions used, key parameters evaluated, conclusions, and basis for the conclusions.

NextEra Response

The following documents were used to develop responses to Questions 1–7 of Reference (4) and in Reference (5). The enclosures are excerpts of approved PBNP documents. Enclosures 4, 6 and 7 contain excerpts from the base calculation and a minor revision.

EXCERPTED DOCUMENT	ENCLOSURE
Cable Ampacity Calculation	3
Breaker Coordination Calculation	4
Functional Times for ESF Equipment for Accident Analysis	5
Loss of Voltage and Underfrequency Relay Settings Calculations	6
Impact on EDG Transient Analysis as a Result of the AFW and AST Modifications Evaluation	7
EDG Fuel Oil System Calculation	8
ETAP AC System Analysis for EPU	9

References

(1) NRC letter to NextEra Energy Point Beach, LLC, dated August 26, 2009, Point Beach Nuclear Plant, Units 1 and 2 – Request for Additional Information from Electrical Engineering Branch Regarding Auxiliary Feedwater (TAC Numbers ME1081 and ME1082) (ML092310454)

(2) FPL Energy Point Beach, LLC letter to NRC, dated April 7, 2009, License Amendment Request 261, Extended Power Uprate (ML091250564)

(3) Regulatory Guide 1.9, Application and Testing of Safety-Related Diesel Generators in Nuclear Power Plants, Revision 4, dated March 2007 (ML070380553)

(4) NextEra Energy Point Beach, LLC letter to NRC, dated June 17, 2009, License Amendment Request 261 Supplement 1, Extended Power Uprate (ML091690090)

(5) NextEra Energy Point Beach, LLC letter to NRC, dated June 17, 2009, License Amendment Request 261 Supplement 2, Extended Power Uprate (ML091690087)

ENCLOSURE 2

NEXTERA ENERGY POINT BEACH, LLC
POINT BEACH NUCLEAR PLANT, UNITS 1 AND 2

LICENSE AMENDMENT REQUEST 261
EXTENDED POWER UPRATE
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION

INFORMATION FOR QUESTION 1 AND 2 RESPONSE
VOLTAGE AND FREQUENCY PROFILES

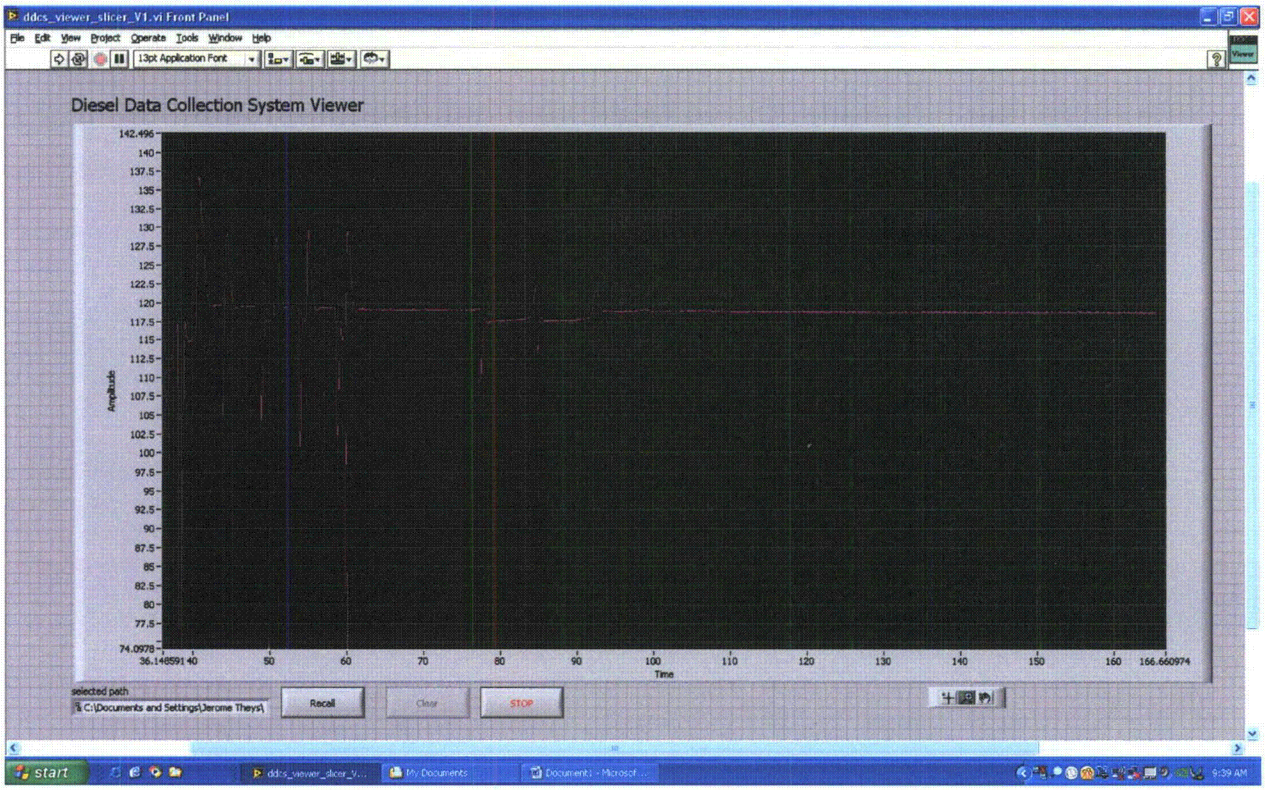
47 pages follow

EDG Voltage and Frequency Plots From Testing

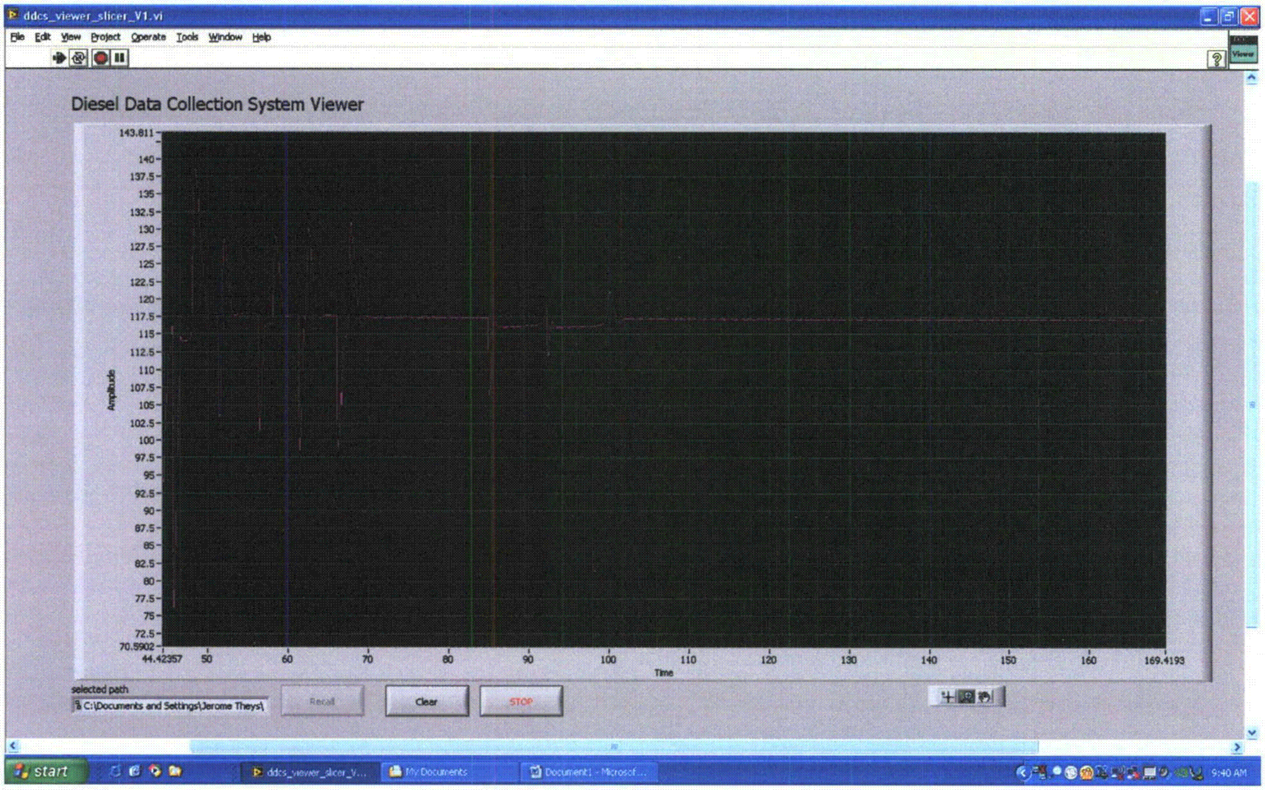
EDG Voltage Plots

Note: Indication is low side of 4200/120 transformer.

G01



G02



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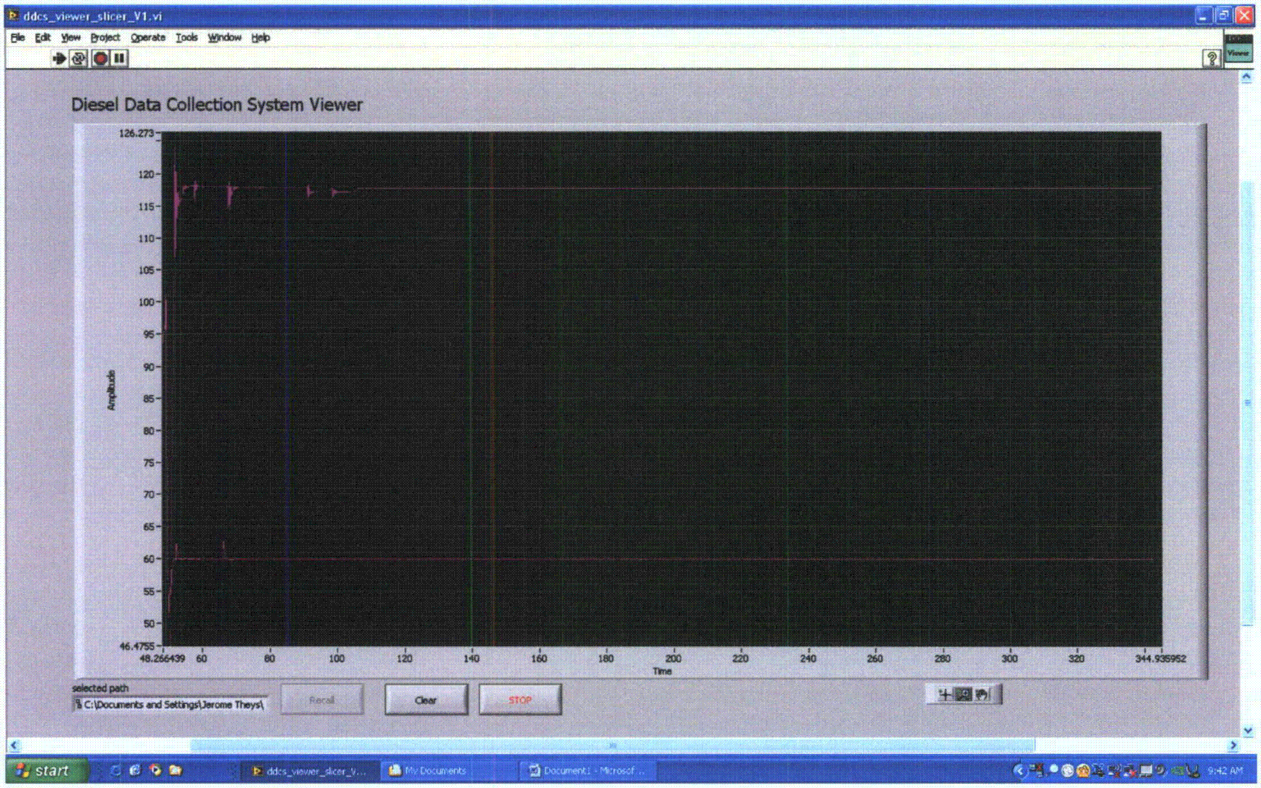
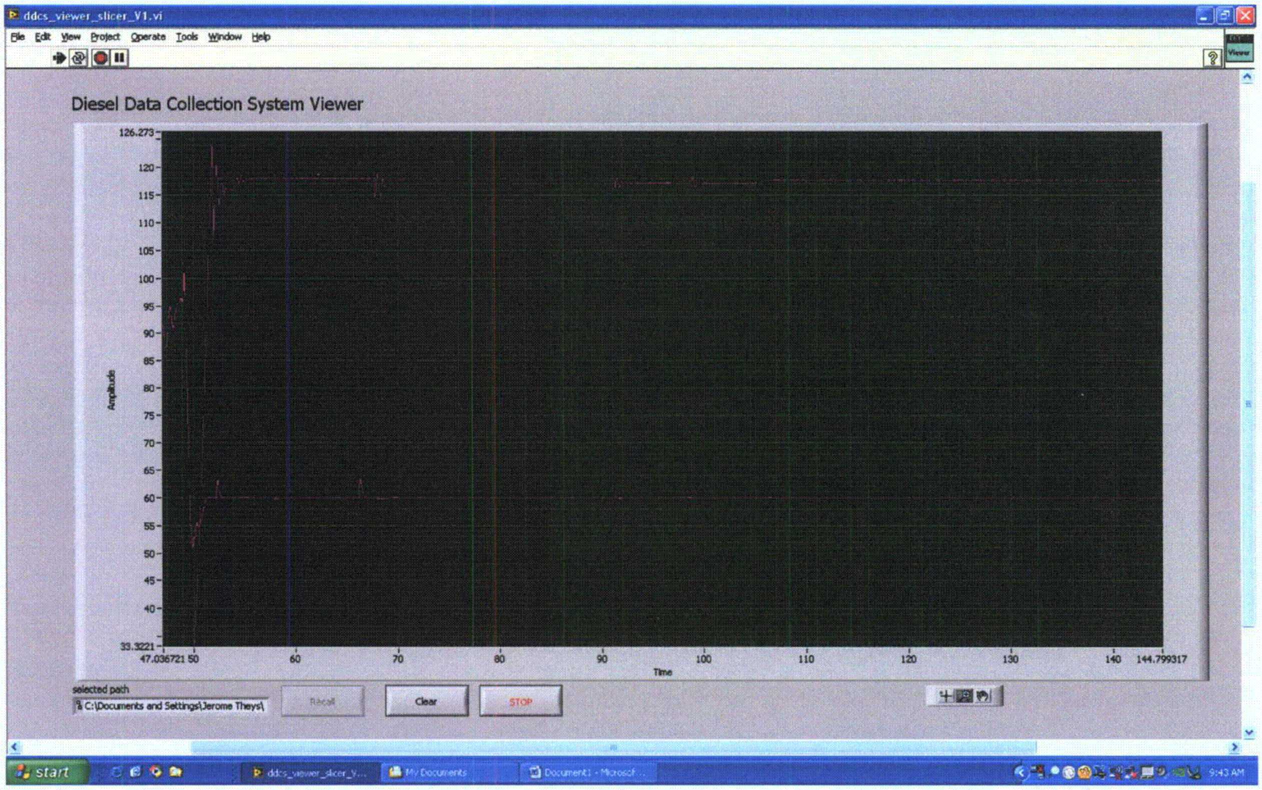
G03

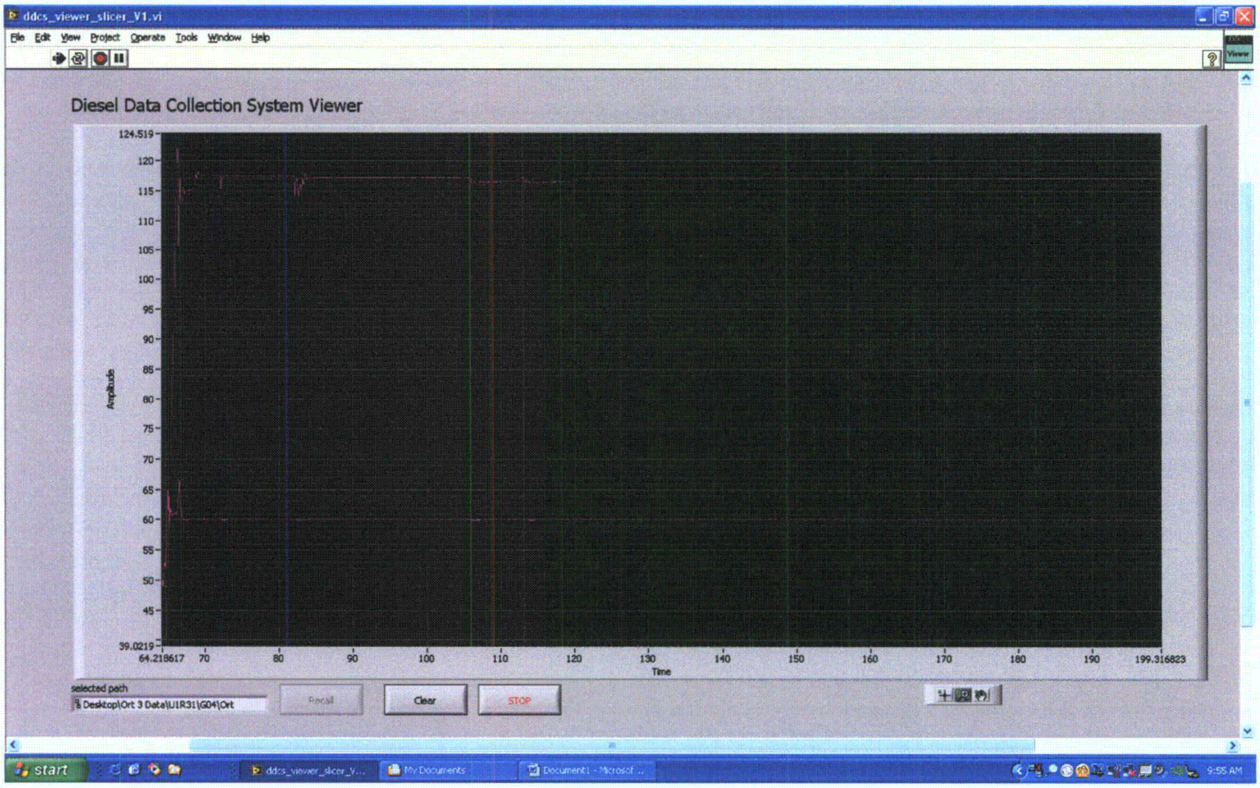
(plot includes voltage and frequency together)

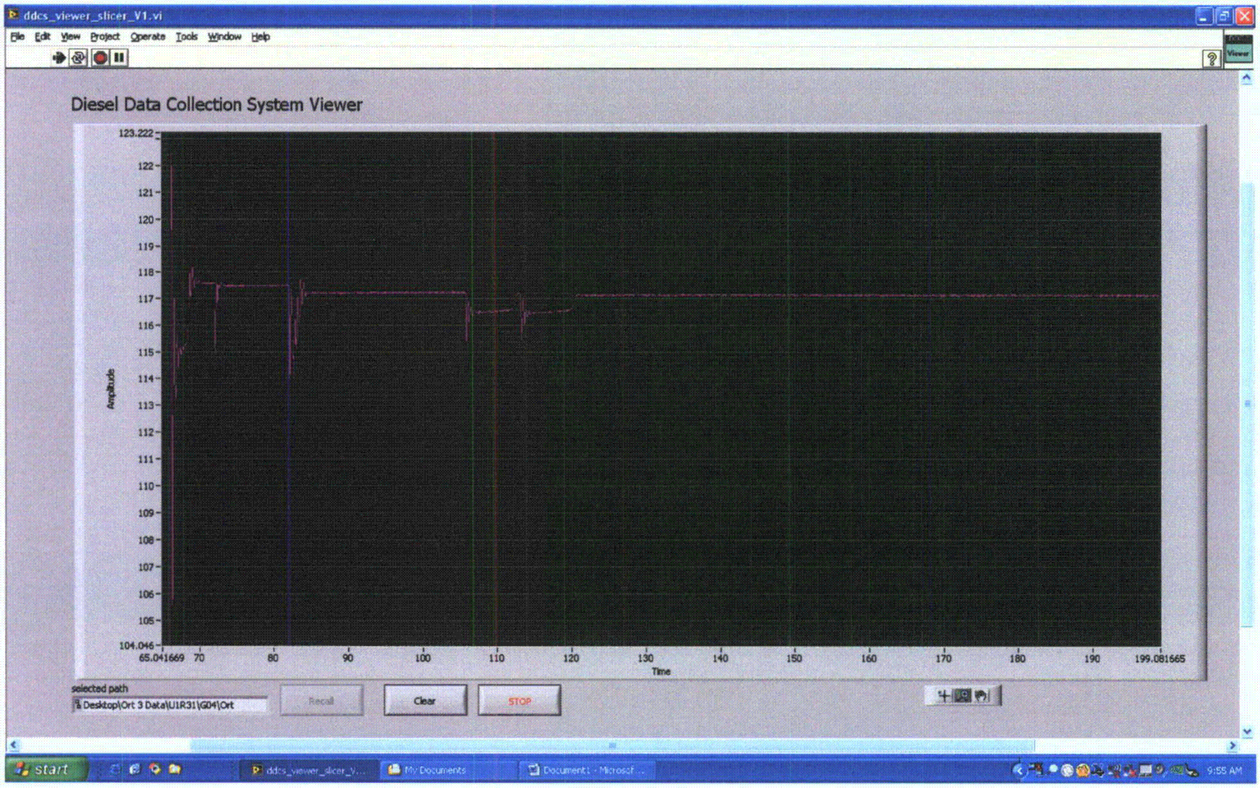




G04

(plot includes voltage and frequency together)

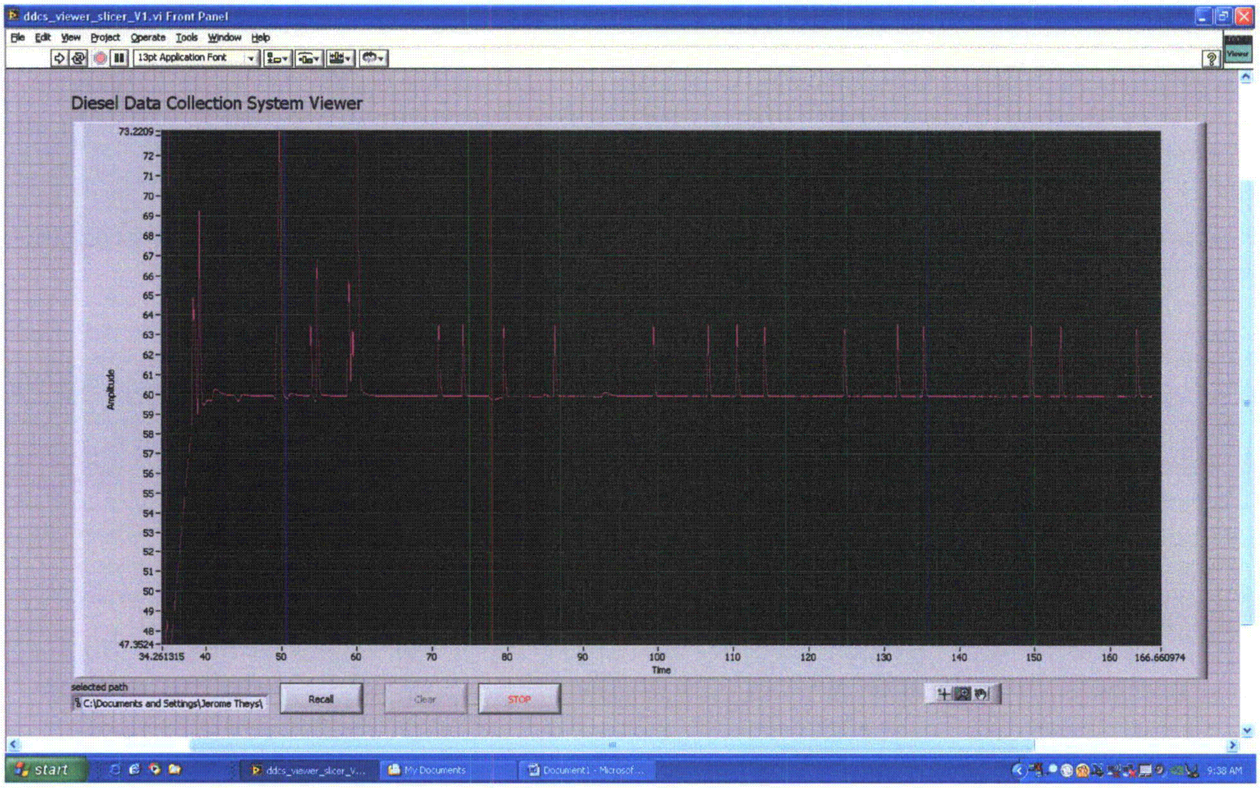




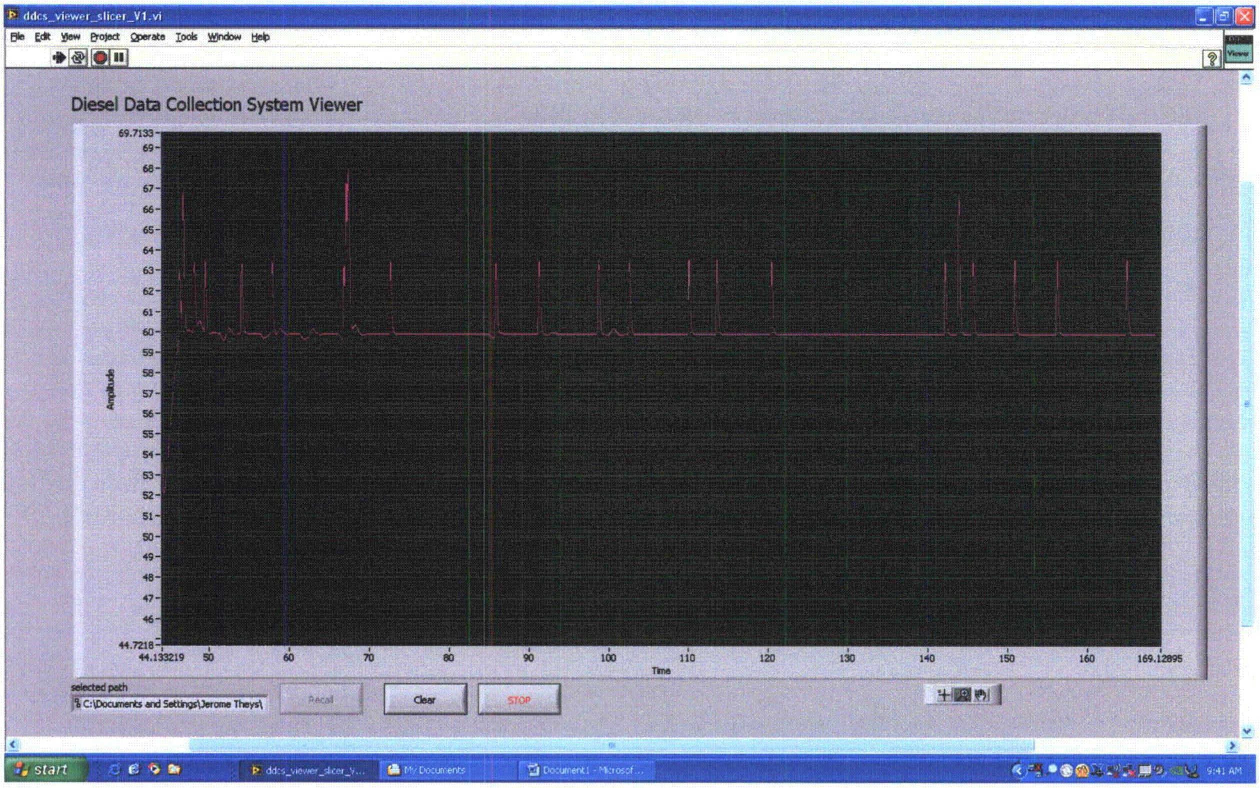
EDG Frequency Plots

Note: Large spikes in the data are present due to noise in the electrical circuits associated with the test equipment. This is most evident in the traces for G01 and G02. The large spikes were verified to be noise by engineering personnel responsible for testing the EDGs.

G01



G02



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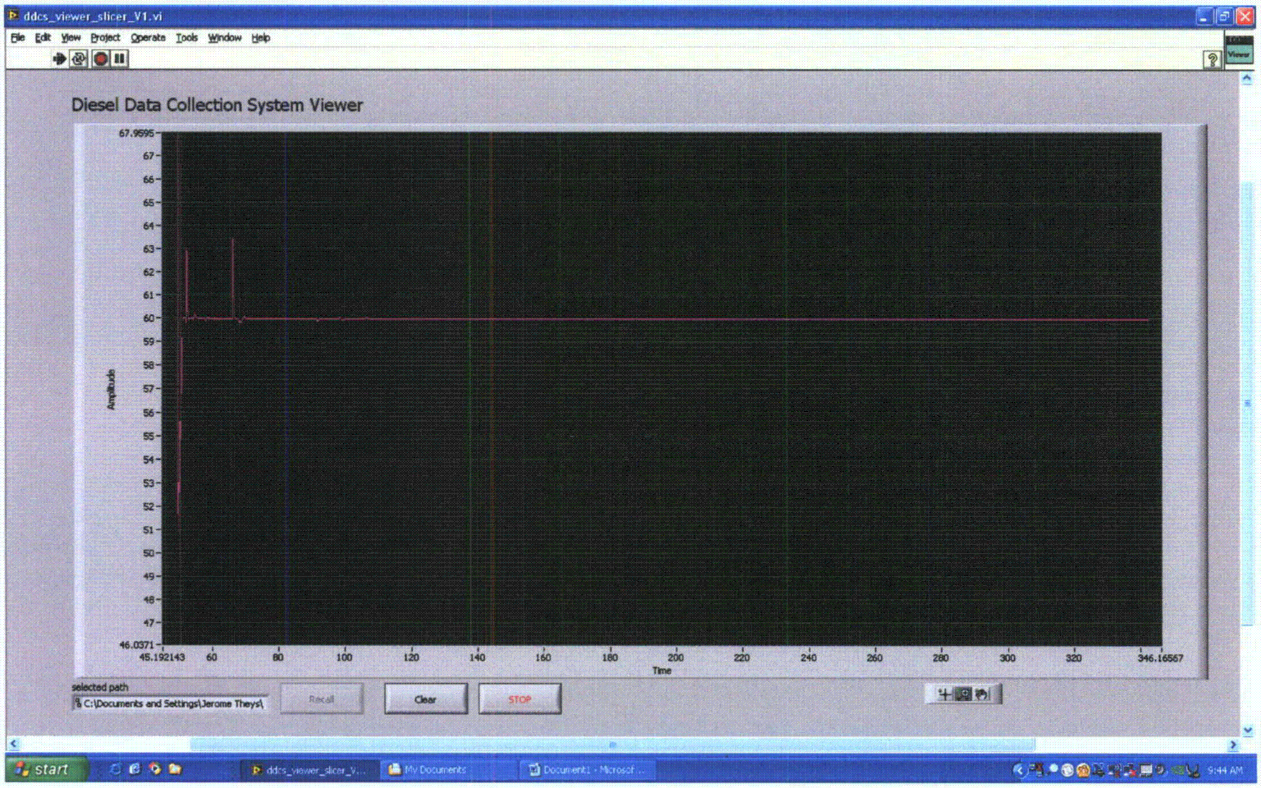
G03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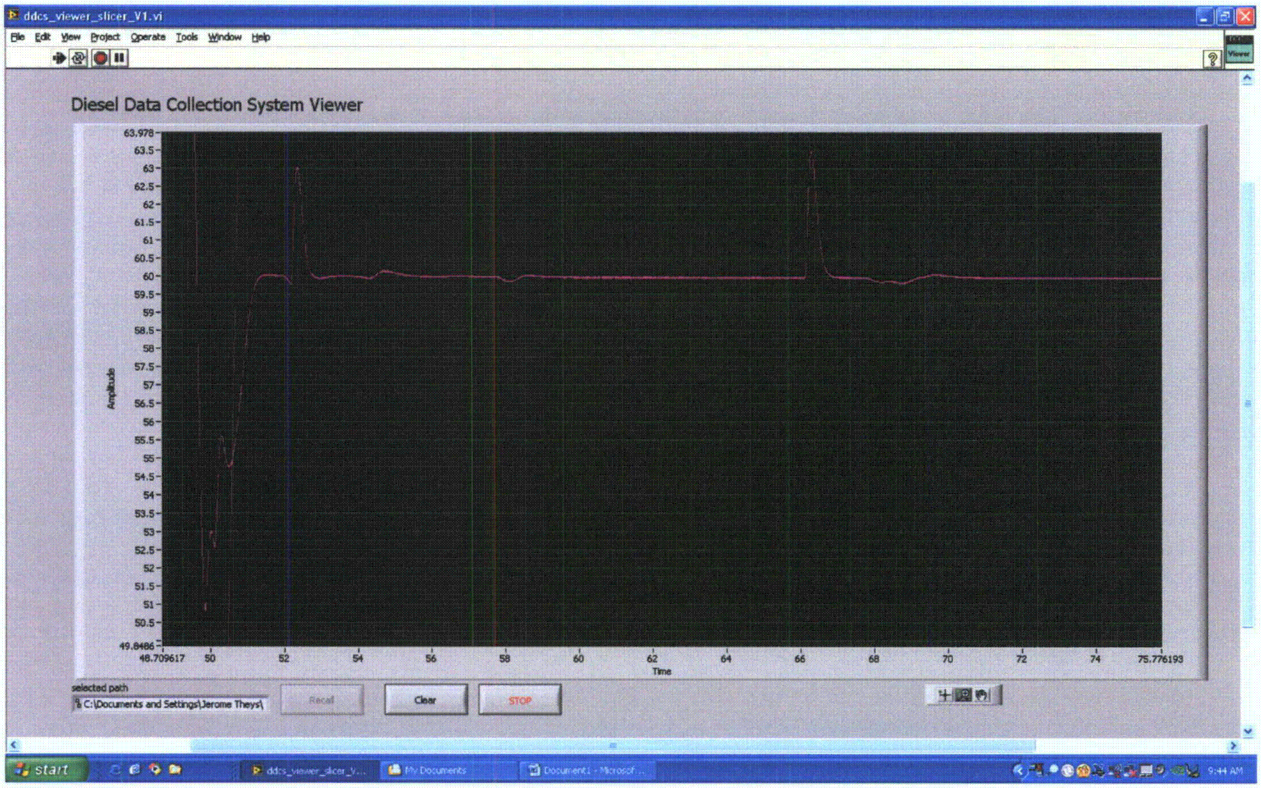
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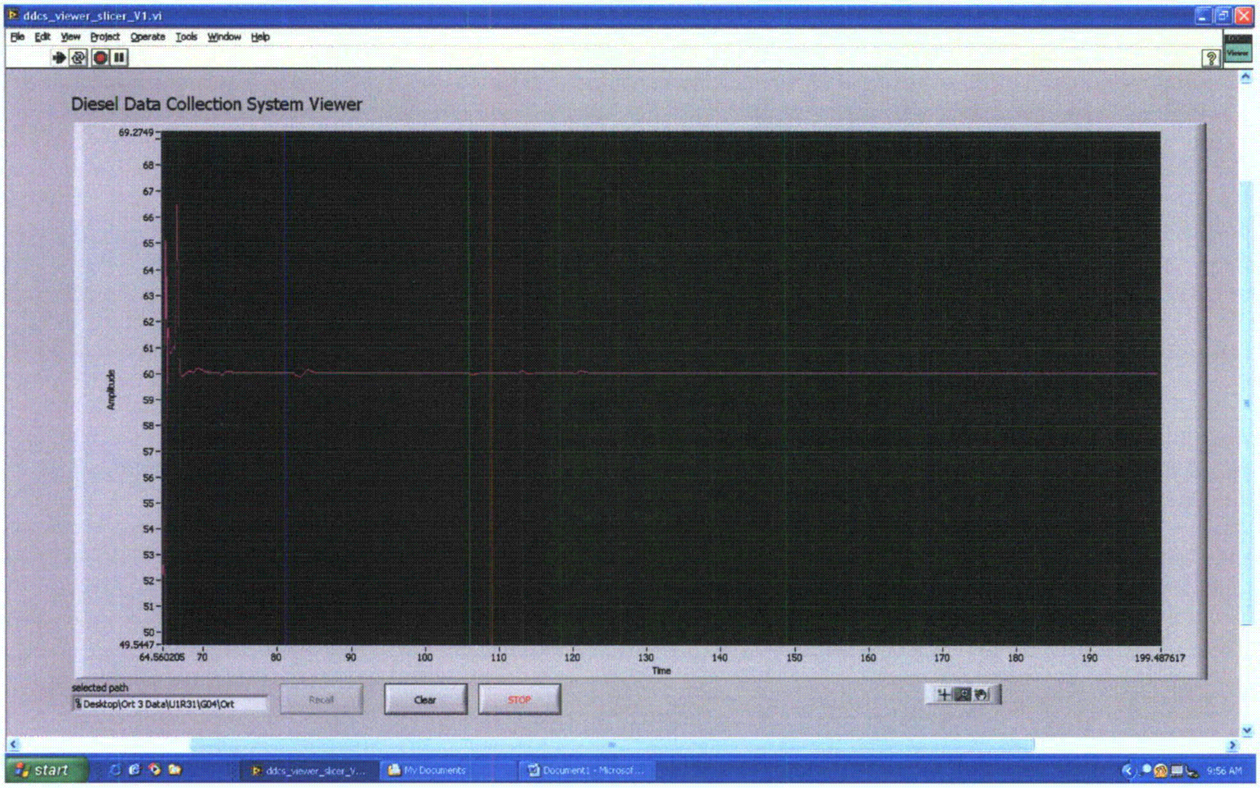
G04



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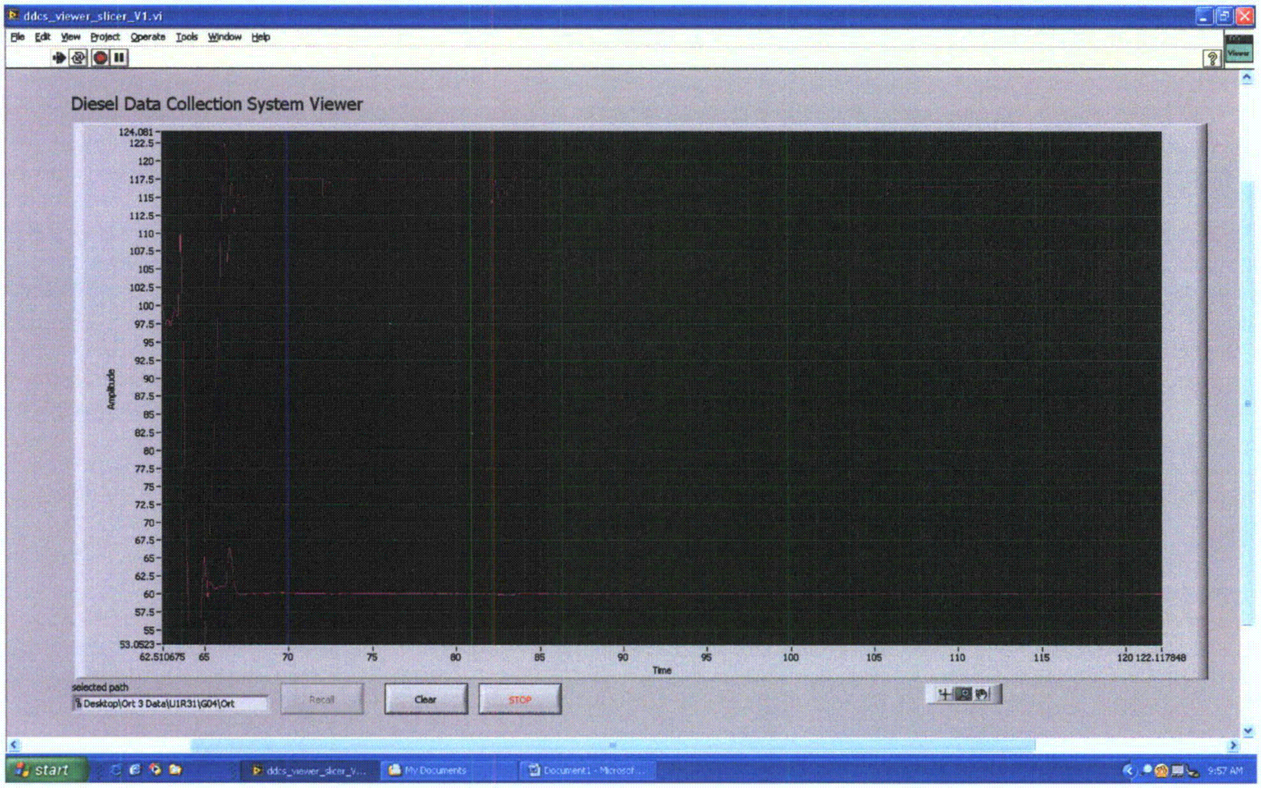

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EDG Voltage and Frequency Profiles From the EDG Transient Load Calculation

The following pages present EDG loading profiles from the EDG transient loading calculation. These profiles did not include auxiliary feedwater system or alternative source term modifications.

Section IV – EDG Transient Loading Analysis

Generator Voltage Profile

A summary of the generator voltage profiles are provided in figures IV-5 through IV-52. The worst-case generator voltage occurred at $t=0^+$ when SI and CCW simultaneously started. The generator voltage initial voltage dips drops to approximately 54% for both G-01 and G-02 in Case 2 and 3 scenarios. However, the generators were capable of recovering back to nominal voltage while starting and accelerating the motors. All subsequent voltage dips during load sequencing were less than the initial voltage dip and remain above 60% voltage. The EDG's were capable of starting and accelerating the safety related motor's while recovering back to nominal voltage.

The worst-case voltage overshoot of G-01 and G-02 occurs after the initial loads of the SI and CCW motor start and complete their acceleration except in DG Case 5 when 2 SW motors start simultaneously. The voltage reaches approximately 129.5% with all subsequent voltage overshoots being lower including the 2 SW motor starts. The momentary voltage overshoots are considered acceptable because the voltage on the system are at these values for less than approximately 2-3 seconds during which the voltage reduces back to normal. The short time duration of the voltage overshoot will not impact the operation of the equipment supplied by the EDG's. Additionally, PBNP performs routine preventative maintenance of the safety related equipment which would identify any long term impacts of the equipment

The voltage profiles of G-03 and G-04 (Cases 1, 4 and 6) are completely enveloped by the voltage profiles of G-01 and G-02 (Cases 2, 3, and 5). The worst-case generator voltage occurs at $t=0^+$ when SI and CCW simultaneously started. The generator voltage initial voltage dips drops to greater than 84% for both G-03 and G-04 in Case 1 and 4 scenarios. The EDG's were capable of recovering back to nominal voltage while starting and accelerating the motors. All subsequent voltage dips during load sequencing were greater than the initial voltage dip and remain above 84% voltage. The EDG's were capable of starting and accelerating the safety related motor's while recovering back to nominal voltage. The worst-case maximum voltage overshoot remained below 100% nominal voltage (Note: the EDG operating point is set at 4050V or 97.4%).

Generator Frequency Profile

A summary of the generator frequency profiles are provided in figures IV-5 through IV-52. A review of the frequency profiles for G-01, G-02, G-03 and G-04 show a range of 58.5 Hz to 60.9 Hz. In each case the frequency recovers to sufficient levels prior to starting of the next sequenced motor.

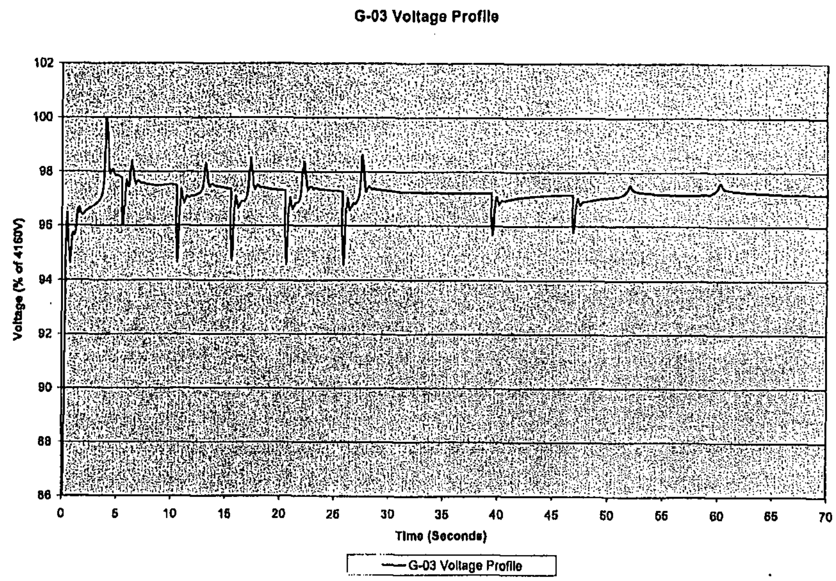
In summary, the results (figures IV-5 through IV-52) of the calculation show that the EDG's are capable of start and accelerate all the required safety related loads following a LOOP (with and without a LOCA). Therefore Acceptance Criteria IV.3.01 has been satisfied.

Section IV – EDG Transient Loading Analysis

IV.7.02.1 Figures IV-5 to IV-12 provide a summary of the results of the EDG transient loading analysis for plant operating condition "DG Case 1." This case is based on the configuration that G-03 supplies both units B-train safeguards buses. Unit 1 is in mode 3 due to a unit trip because of a LOCA and a simultaneous LOOP. Unit 2 is in mode 6 or defueled and the B03/B04 cross-tie is in service. In this configuration, 2B-04 is providing power to 2B-03. Therefore, the require load limitation is that 2P-011A and P-032F are out-of-service (see Section I.2 and IV.8).

Figure IV-5

G-03 Voltage Profile, Plant operating DG Case 1 and study case
DG Case 1-1



Section IV – EDG Transient Loading Analysis

Figure IV-6

G-03 Frequency Profile, Plant operating DG Case 1 and study case DG Case 1-1

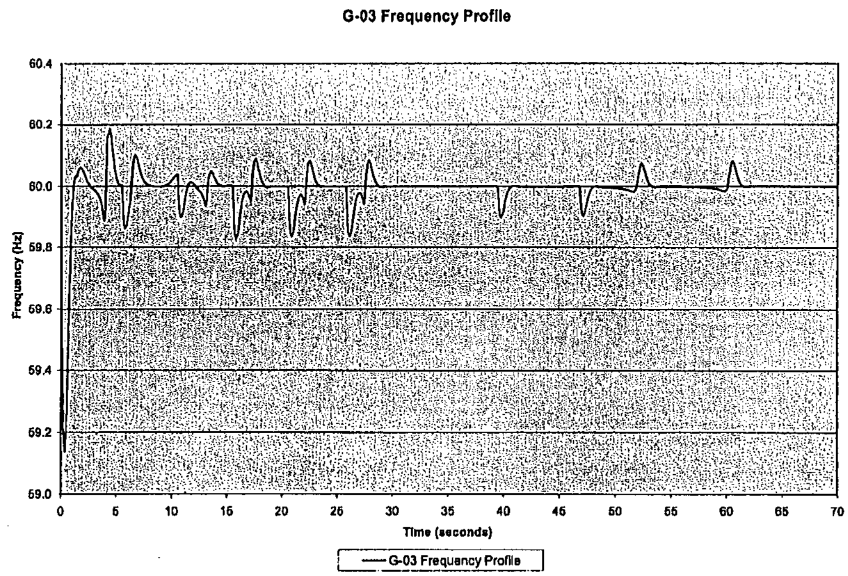


Figure IV-7

G-03 Voltage Profile, Plant operating DG Case 1 and study case DG Case 1-2

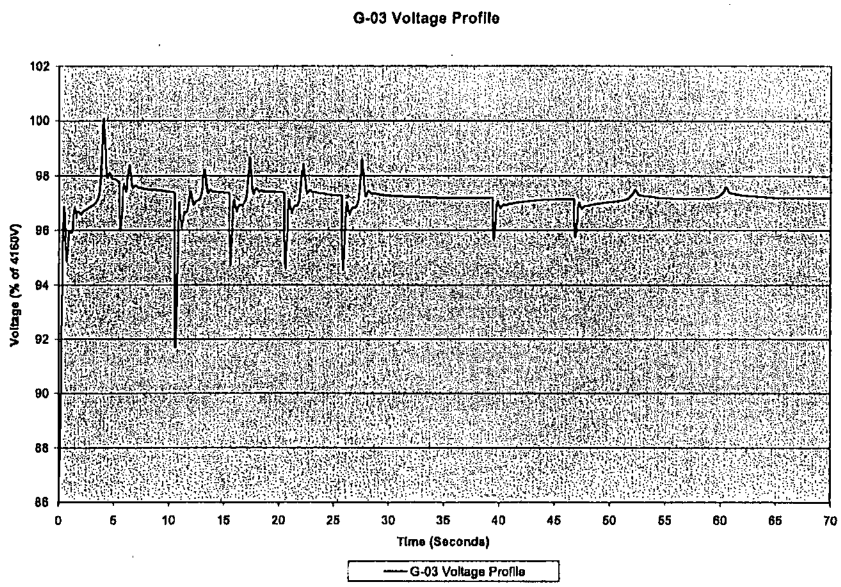


Figure IV-8

G-03 frequency Profile, Plant operating DG Case 1 and study case DG Case 1-2

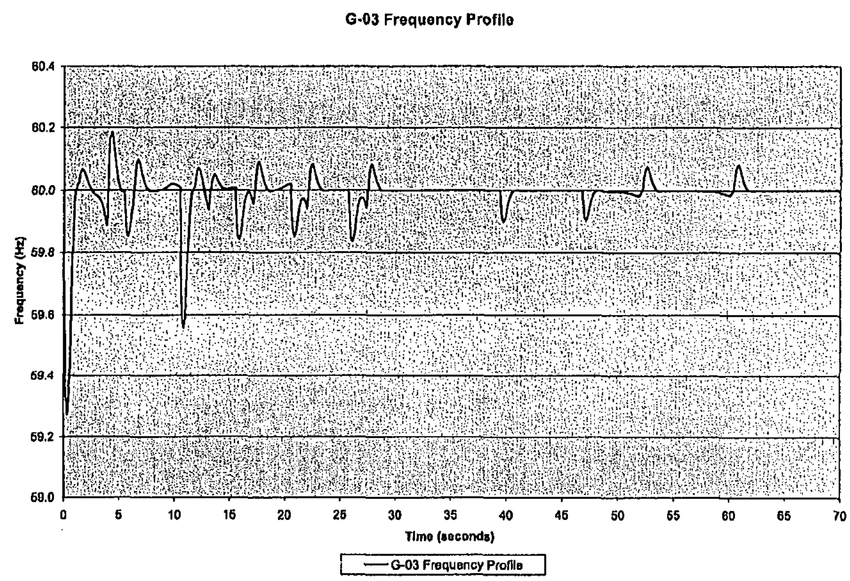
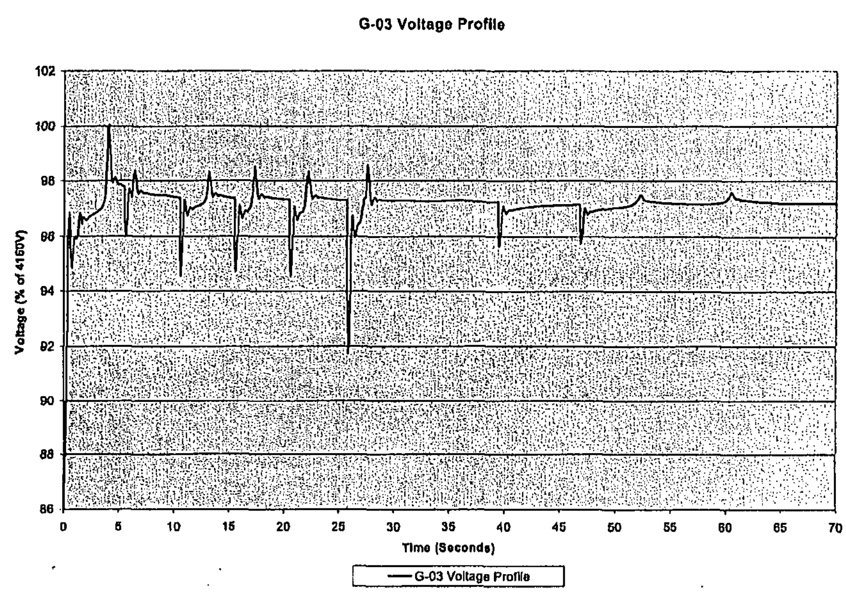


Figure IV-9

G-03 Voltage Profile, Plant operating DG Case 1 and study case DG Case 1-3



Section IV – EDG Transient Loading Analysis

Figure IV-10

G-03 frequency Profile, Plant operating DG Case 1 and study case DG Case 1-3

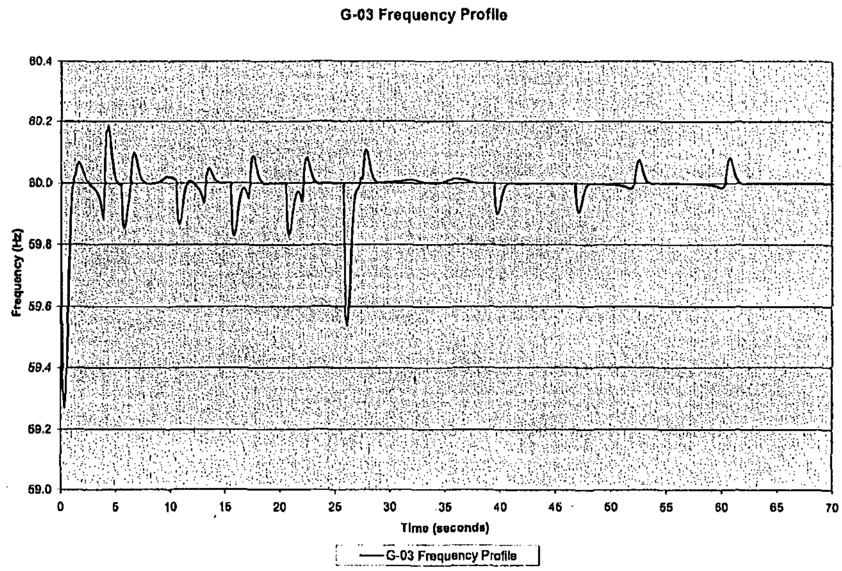
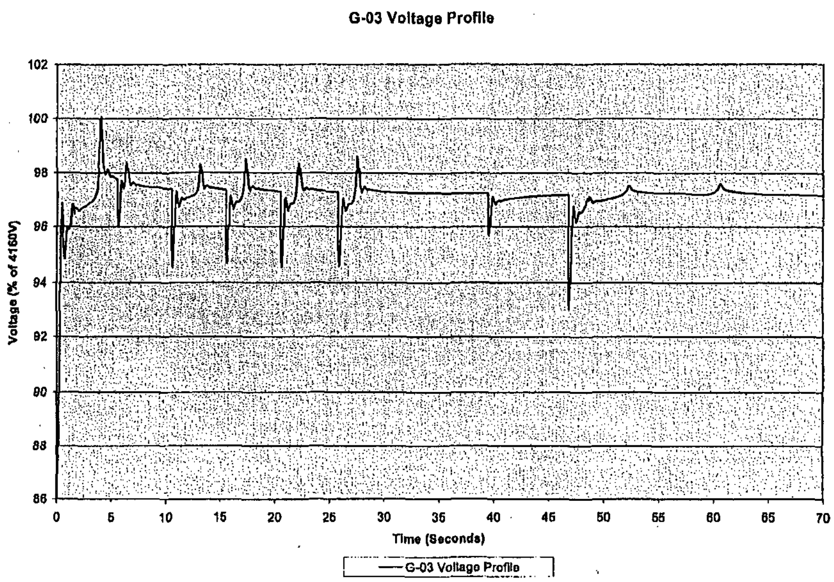


Figure IV-11

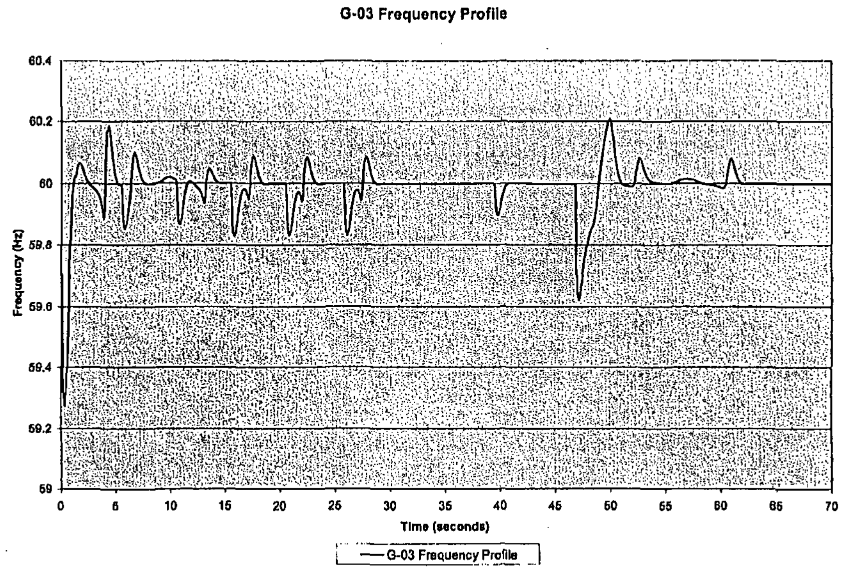
G-03 Voltage Profile, Plant operating DG Case 1 and study case DG Case 1-4



Section IV – EDG Transient Loading Analysis

Figure IV-12

G-03 frequency Profile, Plant operating DG Case 1 and study case DG Case 1-4



Section IV – EDG Transient Loading Analysis

IV.7.02.2. Figures IV-13 to IV-20 provide a summary of the results of the EDG transient loading analysis for plant operating condition "DG Case 2." This case is based on the configuration that G-01 supplies both units A-train safeguards buses. Unit 1 is in mode 3 due to a unit trip because of a LOCA and a simultaneous LOOP. Unit 2 is in mode 6 or defueled and the B03/B04 cross-tie is in service. In this configuration, 2B-03 is providing power to 2B-04. Therefore, the require load limitation is that 2P-011B, P-032D and P-032E are out-of-service (see Section I.2 and IV.8).

Figure IV-13

G-01 Voltage Profile, Plant operating DG Case 2 and study case DG Case 2-1

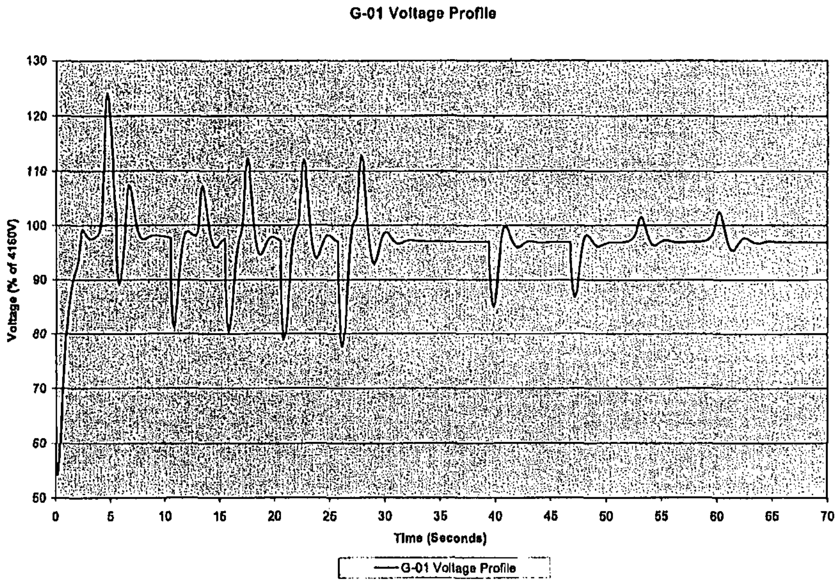


Figure IV-14

G-01 Frequency Profile, Plant operating DG Case 2 and study case DG Case 2-1

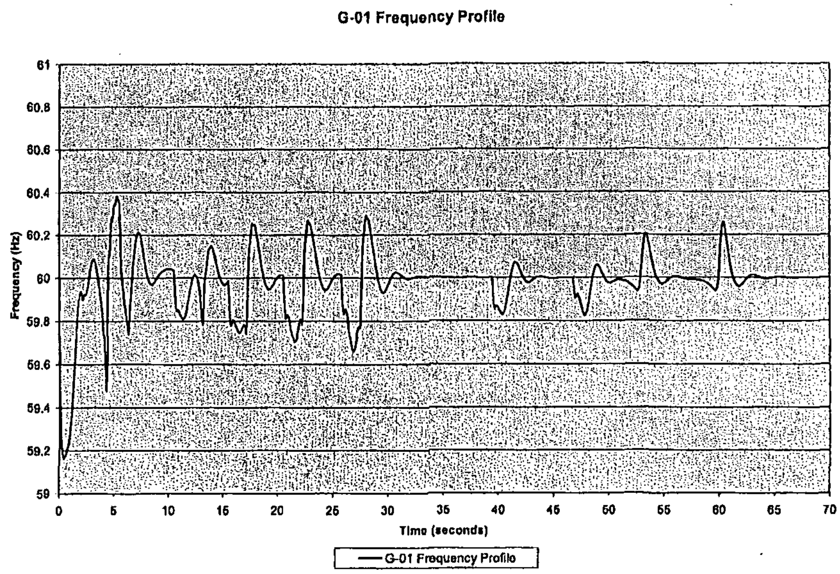
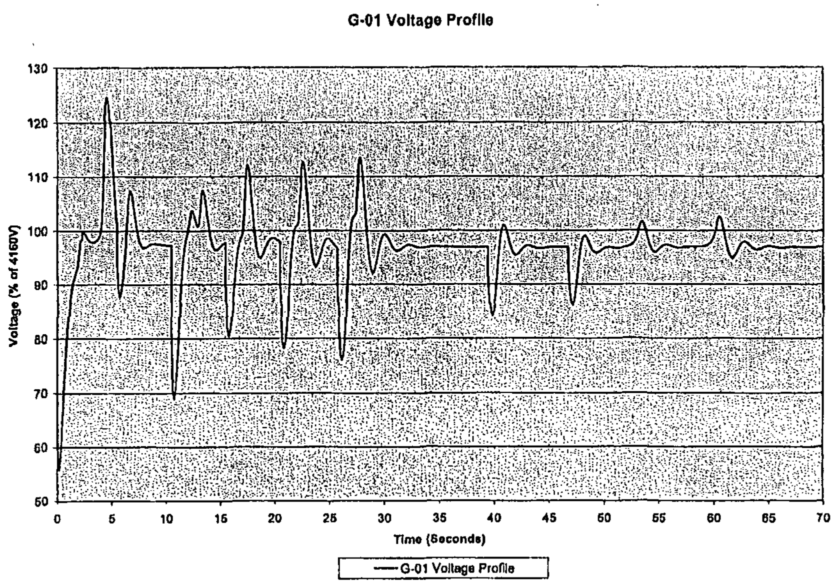


Figure IV-15

G-01 Voltage Profile, Plant operating DG Case 2 and study case DG Case 2-2



Section IV – EDG Transient Loading Analysis

Figure IV-16

G-01 Frequency Profile, Plant operating DG Case 2 and study case DG Case 2-2

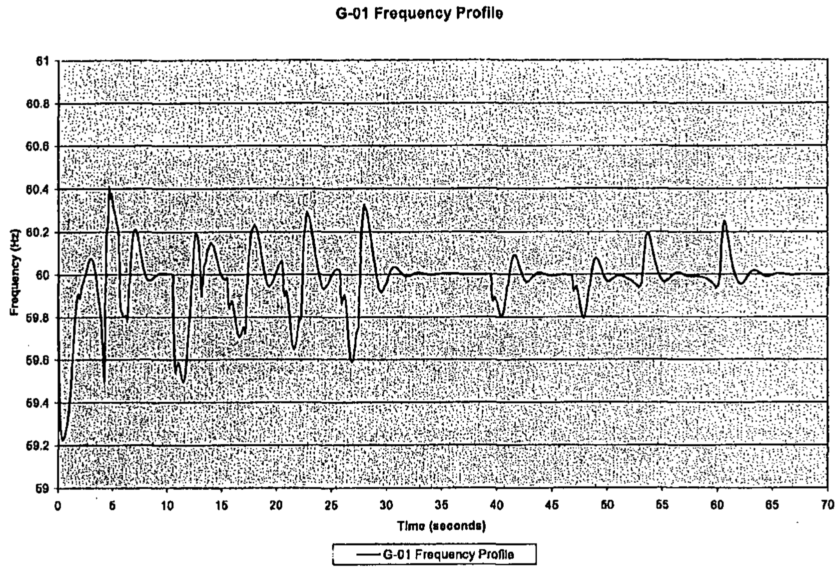
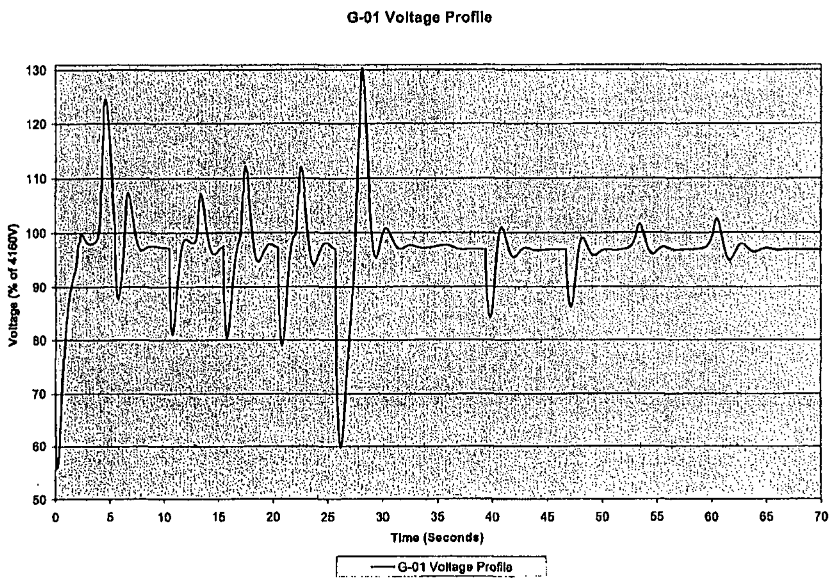


Figure IV-17

G-01 Voltage Profile, Plant operating DG Case 2 and study case DG Case 2-3



Section IV – EDG Transient Loading Analysis

Figure IV-18

G-01 Frequency Profile, Plant operating DG Case 2 and study case DG Case 2-3

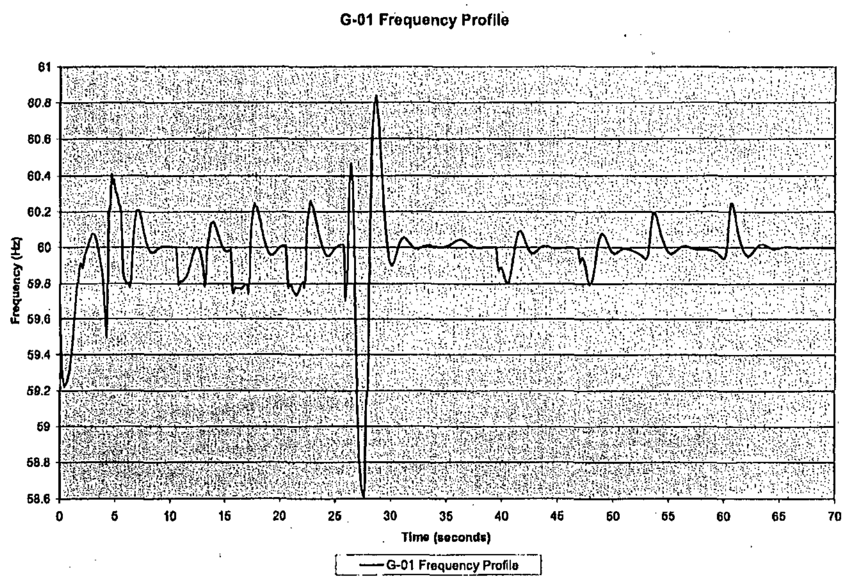
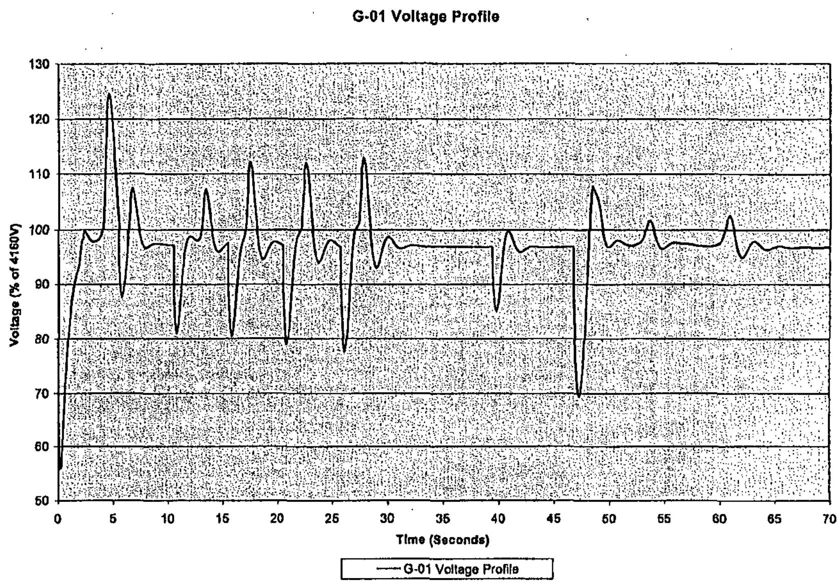


Figure IV-19

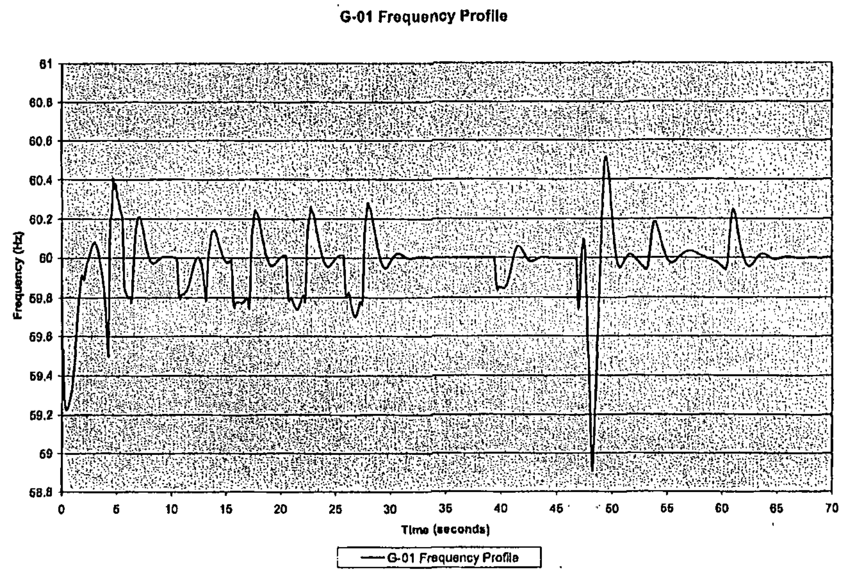
G-01 Voltage Profile, Plant operating DG Case 2 and study case DG Case 2-4



Section IV – EDG Transient Loading Analysis

Figure IV-20

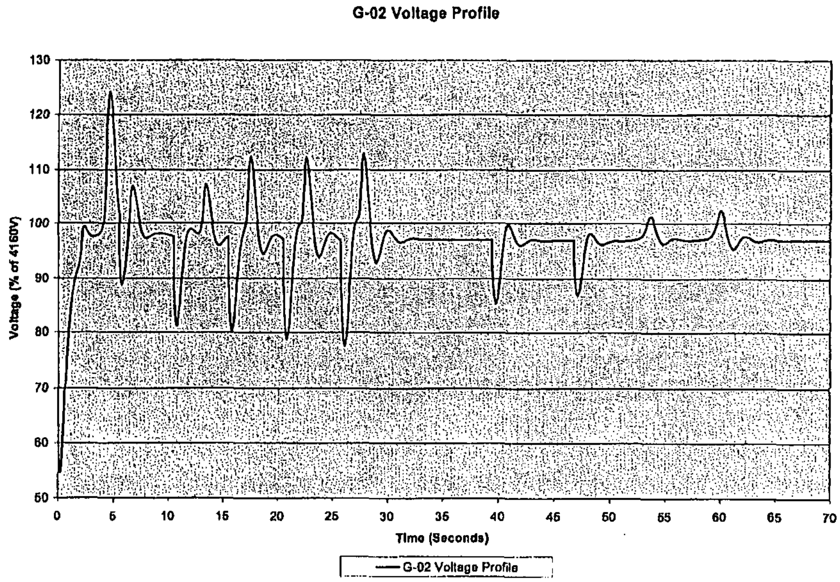
G-01 Frequency Profile, Plant operating DG Case 2 and study case DG Case 2-4



IV.7.02.3 Figures IV-21 to IV-28 provide a summary of the results of the EDG transient loading analysis for plant operating condition "DG Case 3." This case is based on the configuration that G-02 supplies both units A-train safeguards buses. Unit 2 is in mode 3 due to a unit trip because of a LOCA and a simultaneous LOOP. Unit 1 is in mode 6 or defueled and the B03/B04 cross-tie is in service. In this configuration, 1B-03 is providing power to 1B-04. Therefore, the require load limitation is that 1P-011B and P-032C are out-of-service (see Section I.2 and IV.8).

Figure IV-21

G-02 Voltage Profile, Plant operating DG Case 3 and study case DG Case 3-1



Section IV – EDG Transient Loading Analysis

Figure IV-22

G-02 Frequency Profile, Plant operating DG Case 3 and study case DG Case 3-1

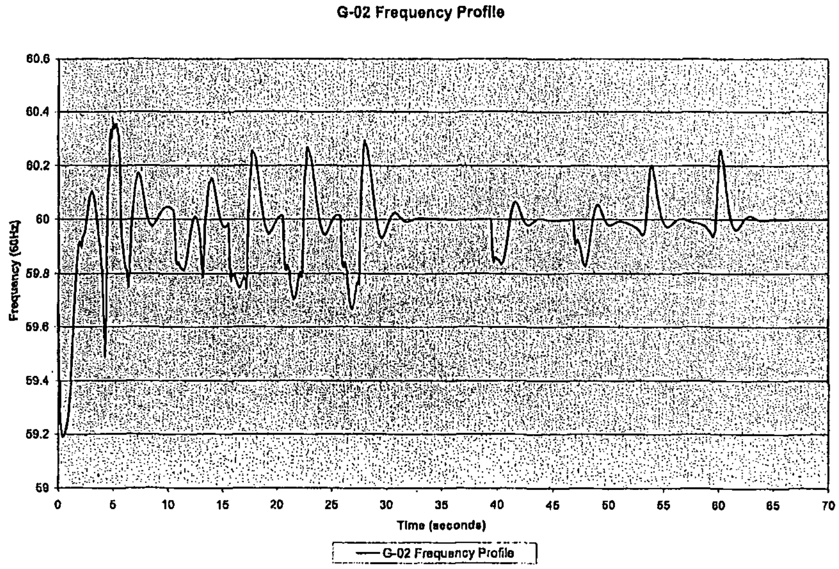
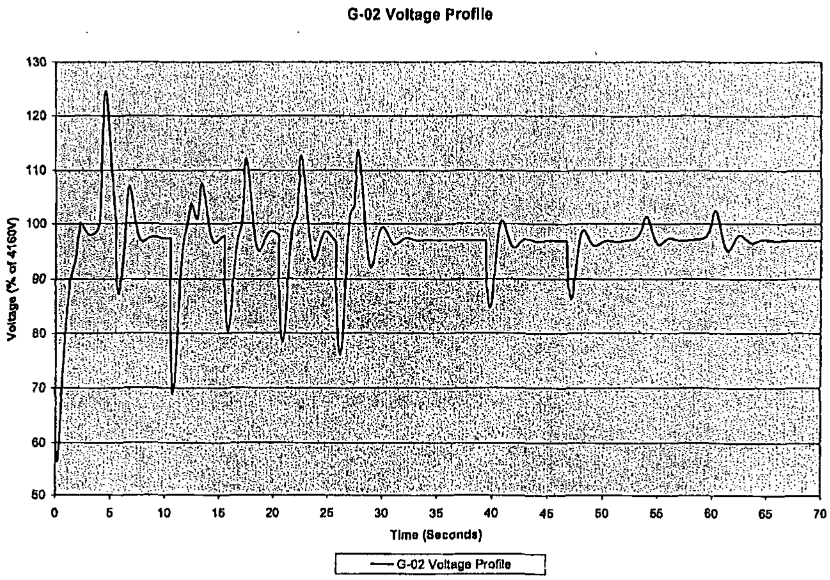


Figure IV-23

G-02 Voltage Profile, Plant operating DG Case 3 and study case DG Case 3-2



Section IV – EDG Transient Loading Analysis

Figure IV-24

G-02 Frequency Profile, Plant operating DG Case 3 and study case DG Case 3-2

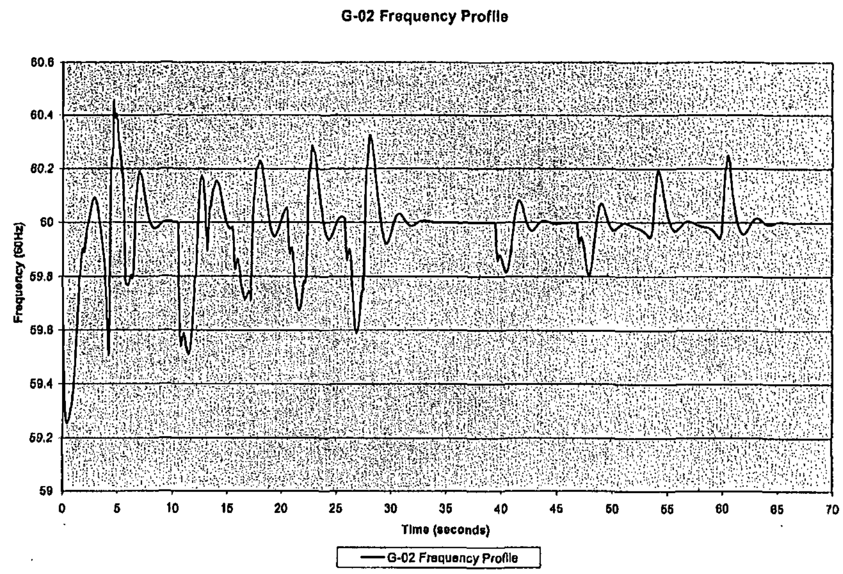


Figure IV-25

G-02 Voltage Profile, Plant operating DG Case 3 and study case DG Case 3-3

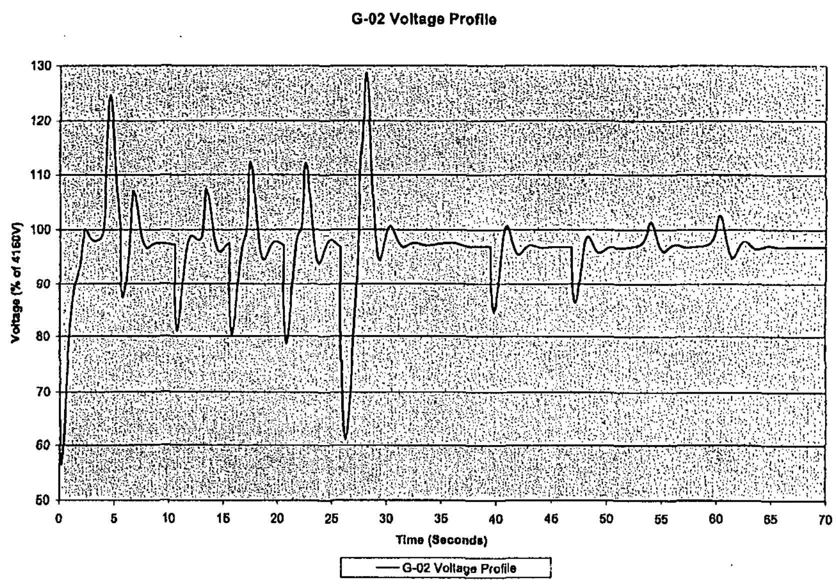


Figure IV-26

G-02 Frequency Profile, Plant operating DG Case 3 and study case DG Case 3-3

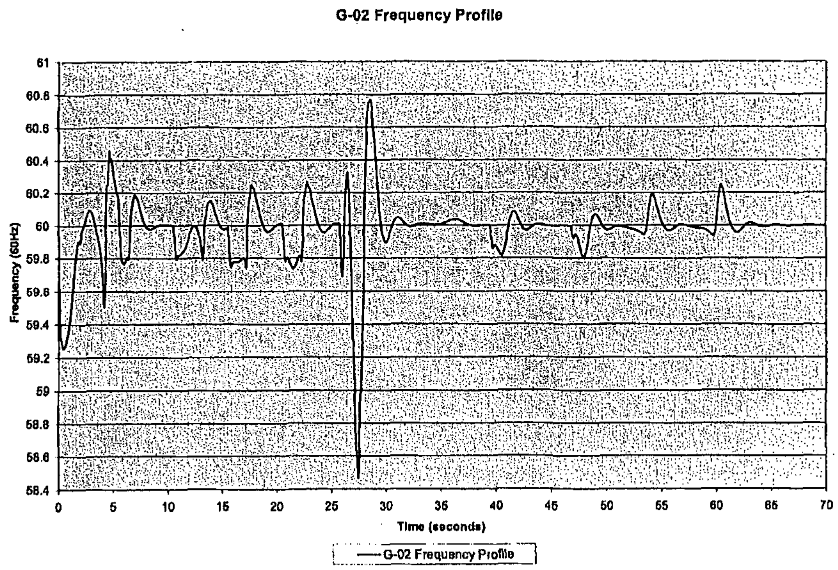
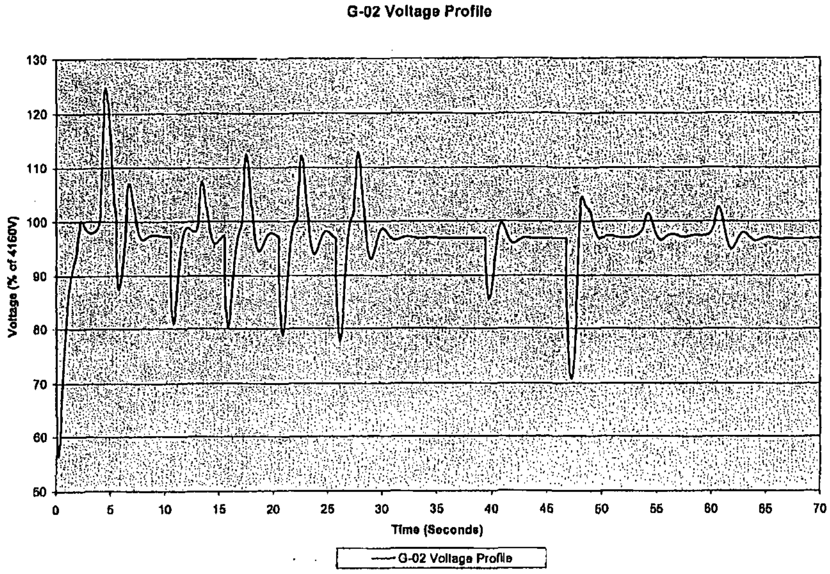


Figure IV-27

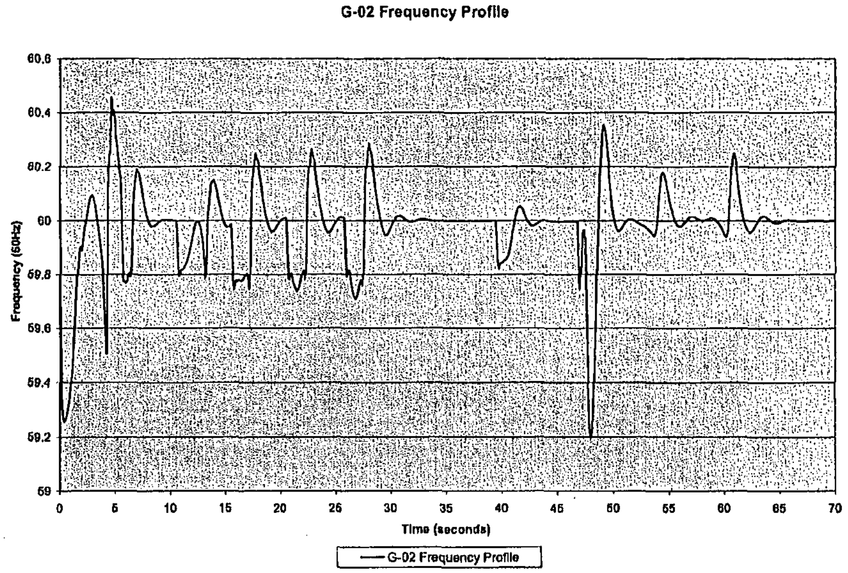
G-02 Voltage Profile, Plant operating DG Case 3 and study case DG Case 3-4



Section IV – EDG Transient Loading Analysis

Figure IV-28

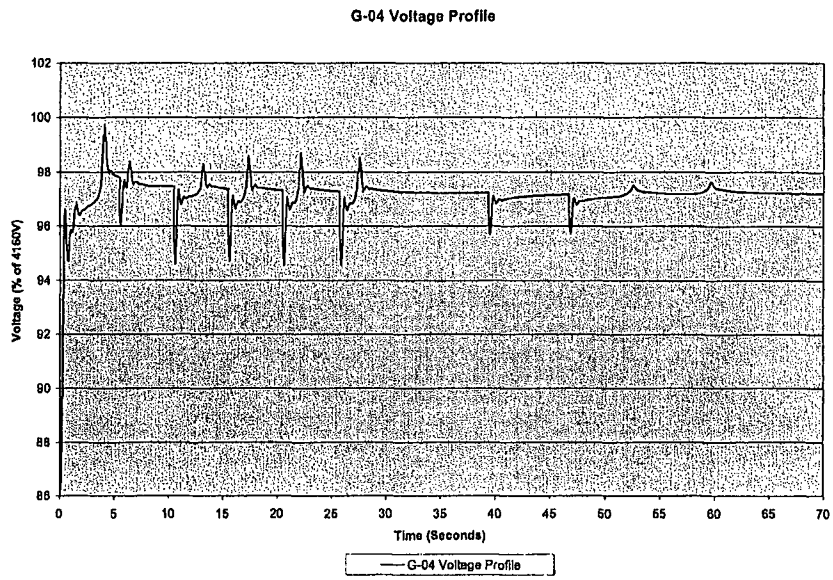
G-02 Frequency Profile, Plant operating DG Case 3 and study case DG Case 3-4



IV.7.02.4 Figures IV-29 to IV-36 provide a summary of the results of the EDG transient loading analysis for plant operating condition "DG Case 4." This case is based on the configuration that G-04 supplies both units B-train safeguards buses. Unit 2 is in mode 3 due to a unit trip because of a LOCA and a simultaneous LOOP. Unit 1 is in mode 6 or defueled and the B03/B04 cross-tie is in service. In this configuration, 1B-04 is providing power to 1B-03. Therefore, the require load limitation is that 1P-011A, P-032A and P-032B are out-of-service (see Section I.2 and IV.8).

Figure IV-29

G-04 Voltage Profile, Plant operating DG Case 4 and study case DG Case 4-1



Section IV – EDG Transient Loading Analysis

Figure IV-30

G-04 Frequency Profile, Plant operating DG Case 4 and study case DG Case 4-1

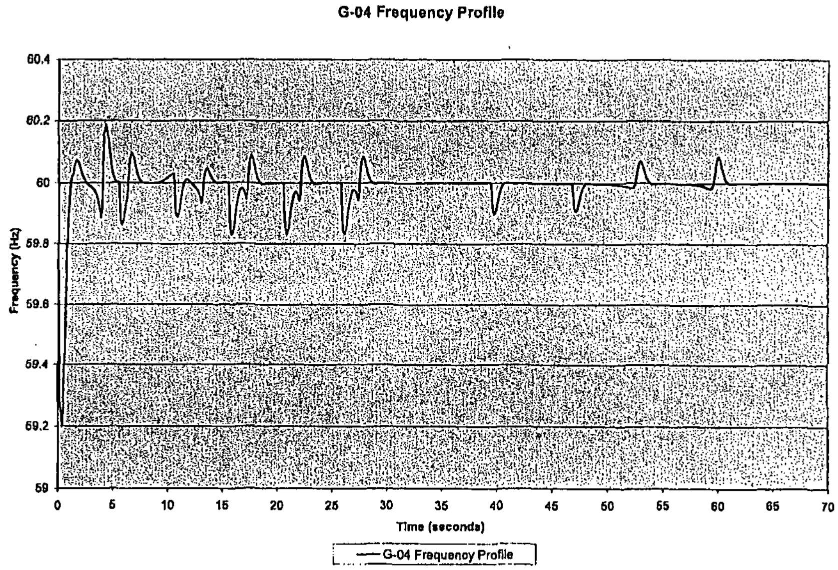
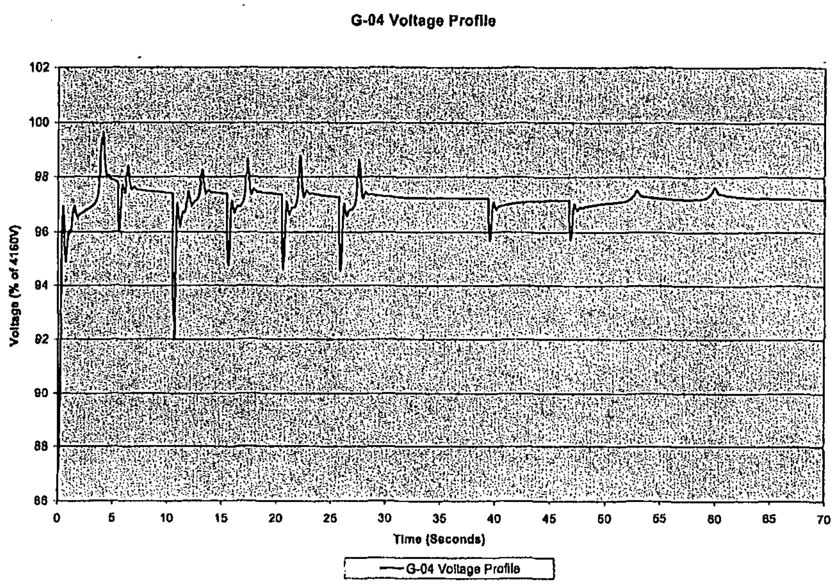


Figure IV-31

G-04 Voltage Profile, Plant operating DG Case 4 and study case DG Case 4-2



Section IV – EDG Transient Loading Analysis

Figure IV-32

G-04 Frequency Profile, Plant operating DG Case 4 and study case DG Case 4-2

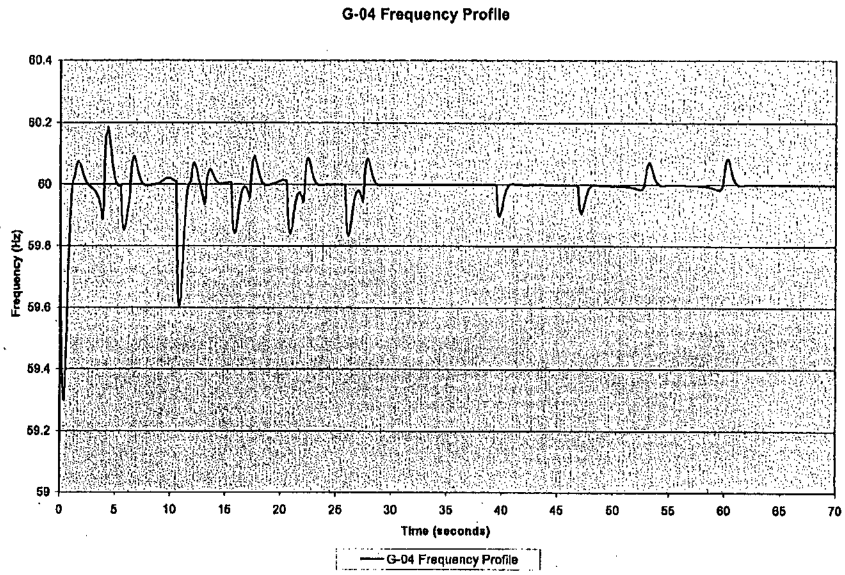
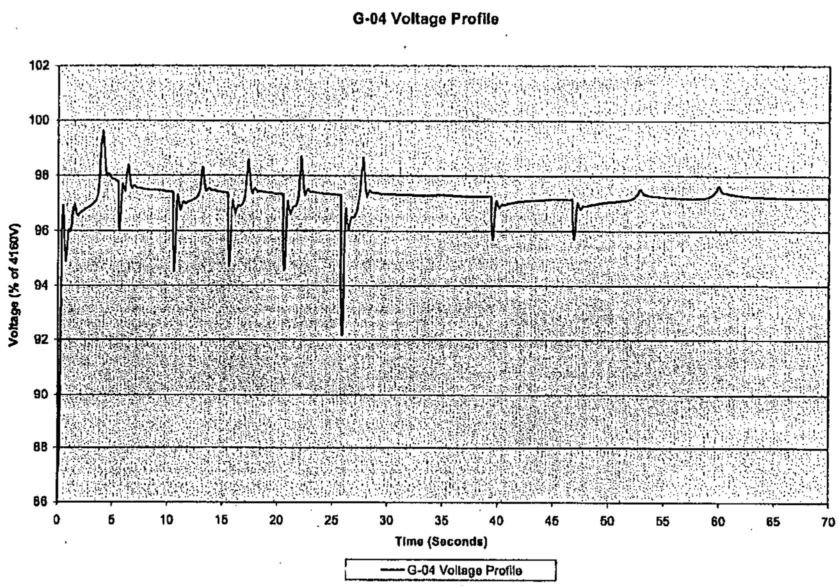


Figure IV-33

G-04 Voltage Profile, Plant operating DG Case 4 and study case DG Case 4-3



Section IV – EDG Transient Loading Analysis

Figure IV-34

G-04 Frequency Profile, Plant operating DG Case 4 and study case DG Case 4-3

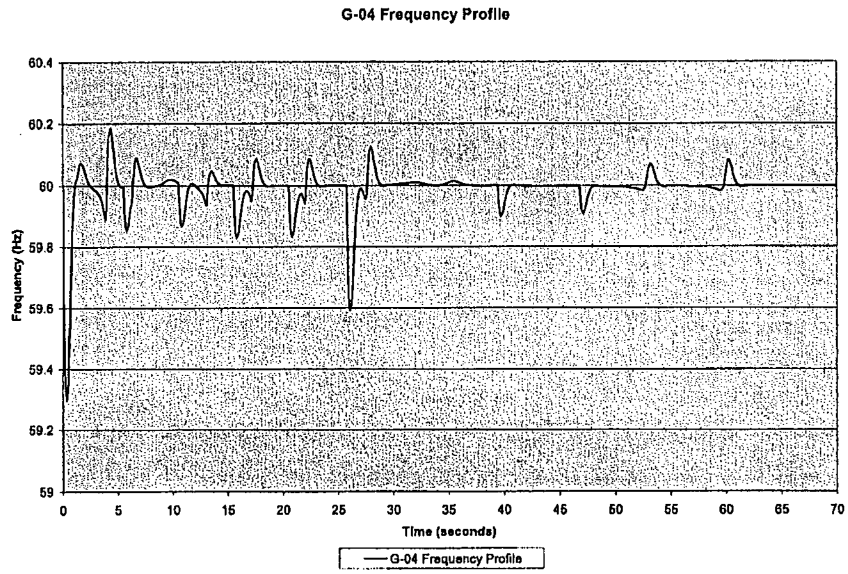
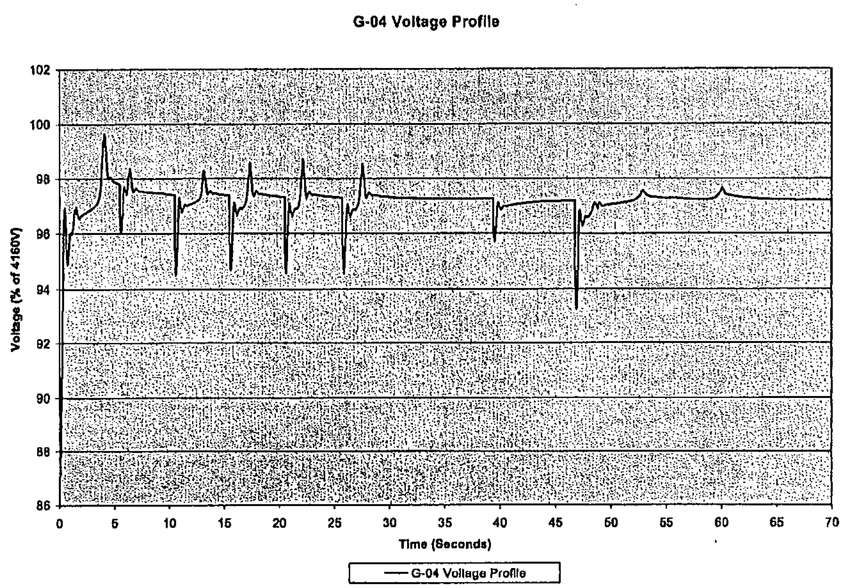


Figure IV-35

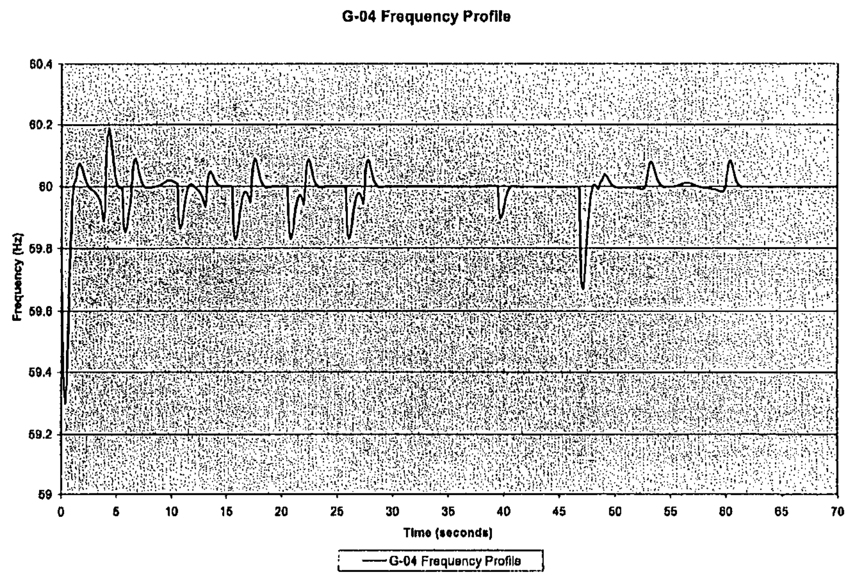
G-04 Voltage Profile, Plant operating DG Case 4 and study case DG Case 4-4



Section IV – EDG Transient Loading Analysis

Figure IV-36

G-04 Frequency Profile, Plant operating DG Case 4 and study case DG Case 4-4



Section IV – EDG Transient Loading Analysis

IV.7.02.5 Figures IV-37 to IV-44 provide a summary of the results of the EDG transient loading analysis for plant operating condition "DG Case 5." This case is based on the configuration that G-01 supplies Unit 1 A train safeguards loads and G-02 supplies Unit 2 A train safeguards loads. Unit 1 and Unit 2 are in mode 6 or defueled and the B03/B04 cross-tie is in-service and a LOOP occurs. Case 5 is evaluating the worst-case response in this alignment for both Unit 1 and Unit 2. Therefore, the common loads are conservatively considered to have a start signal as a result of an opposite unit event (e.g. SI).

Figure IV-37

G-01 Voltage Profile, Plant operating DG Case 5 and study case DG Case 5-1

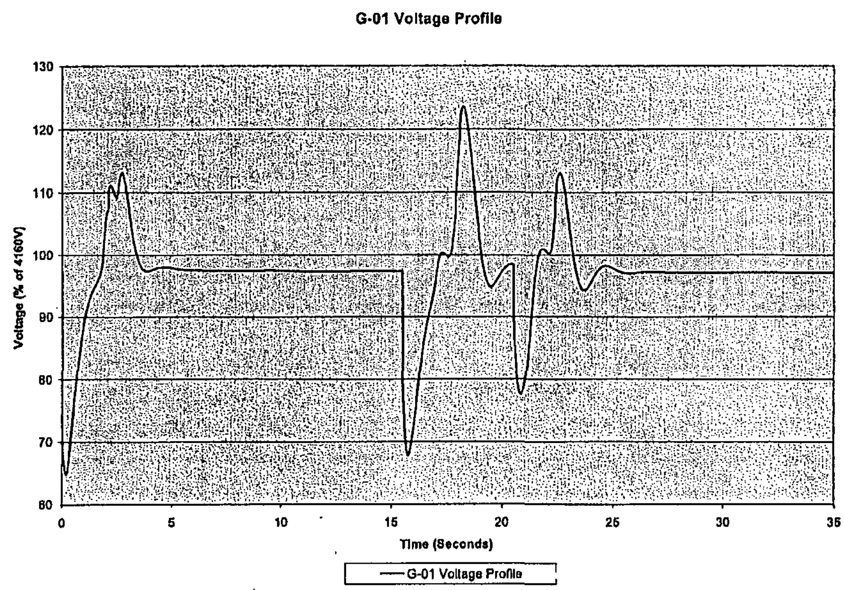


Figure IV-38

G-01 Frequency Profile, Plant operating DG Case 5 and study case DG Case 5-1

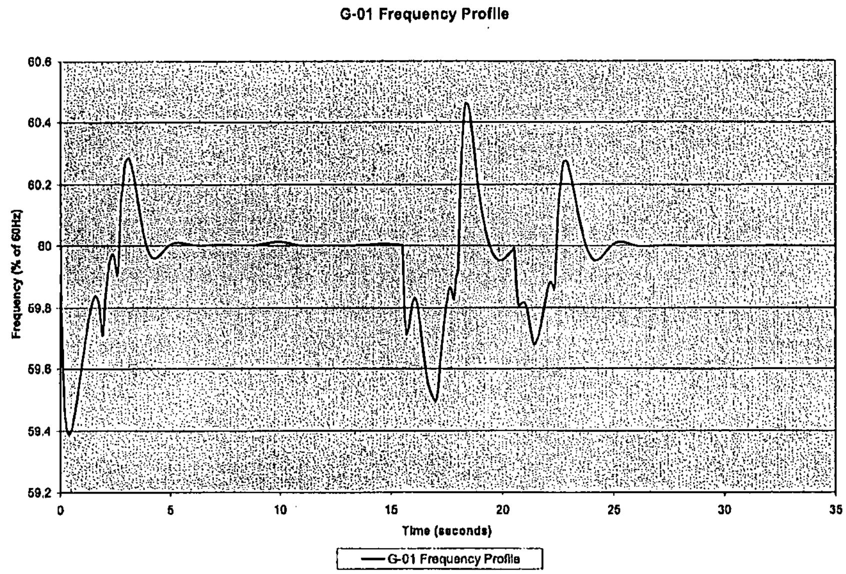


Figure IV-39

G-02 Voltage Profile, Plant operating DG Case 5 and study case DG Case 5-1

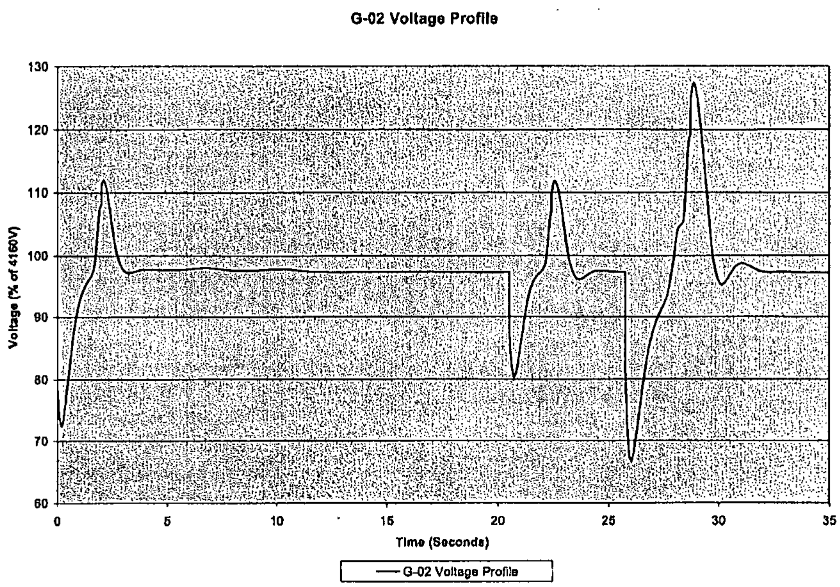


Figure IV-40

G-02 Frequency Profile, Plant operating DG Case 5 and study case DG Case 5-1

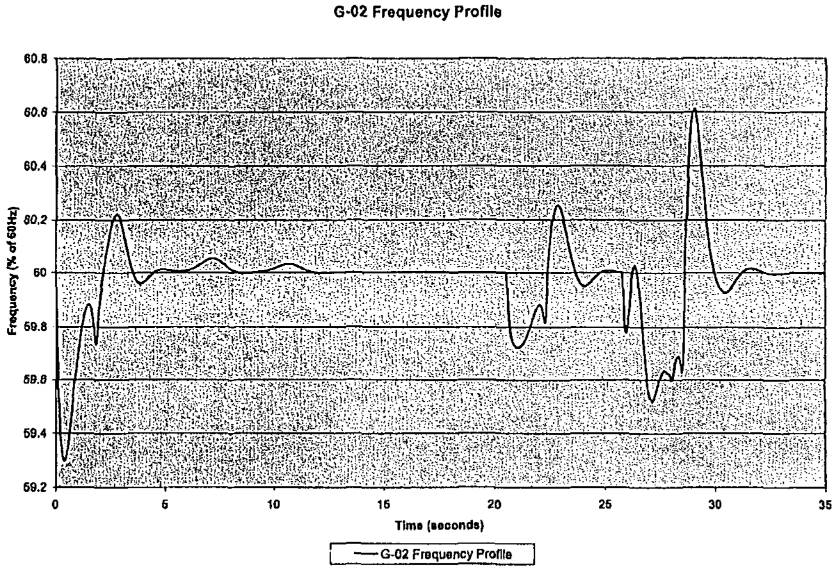
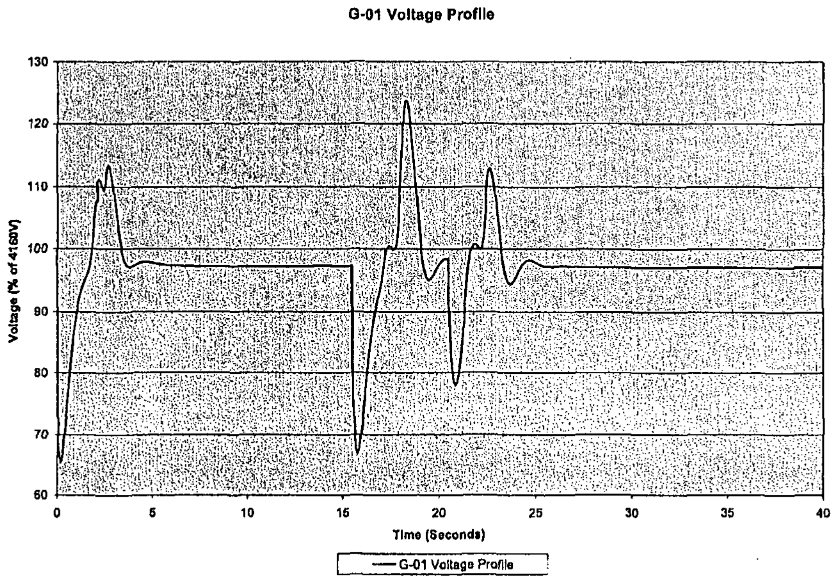


Figure IV-41

G-01 Voltage Profile, Plant operating DG Case 5 and study case DG Case 5-2



Section IV – EDG Transient Loading Analysis

Figure IV-42

G-01 Frequency Profile, Plant operating DG Case 5 and study case DG Case 5-2

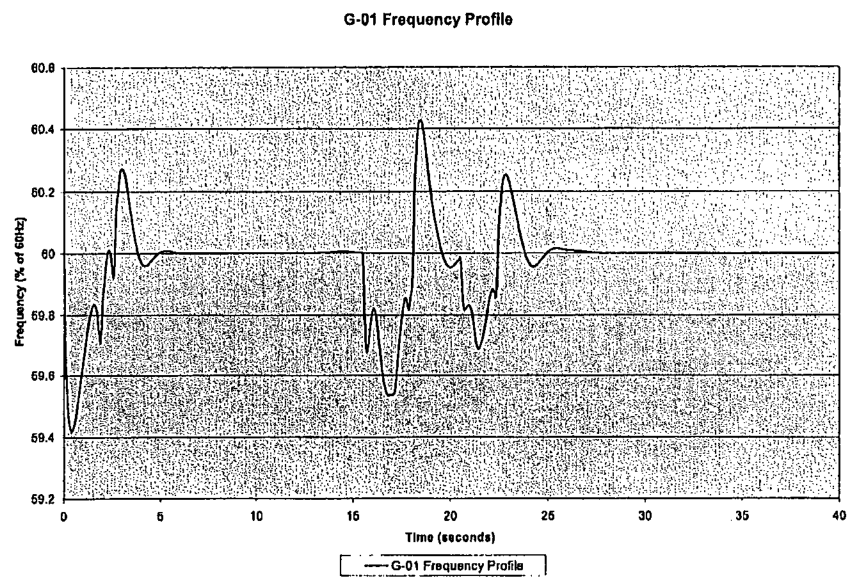
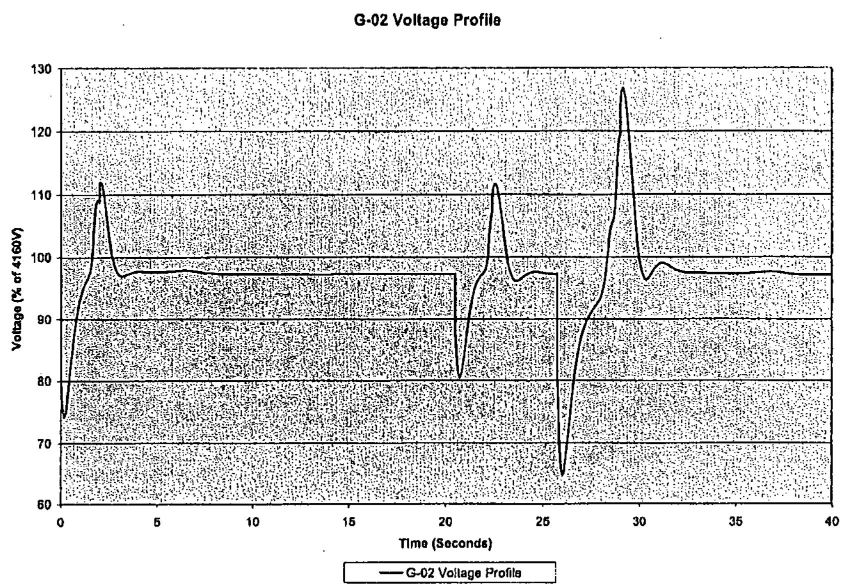


Figure IV-43

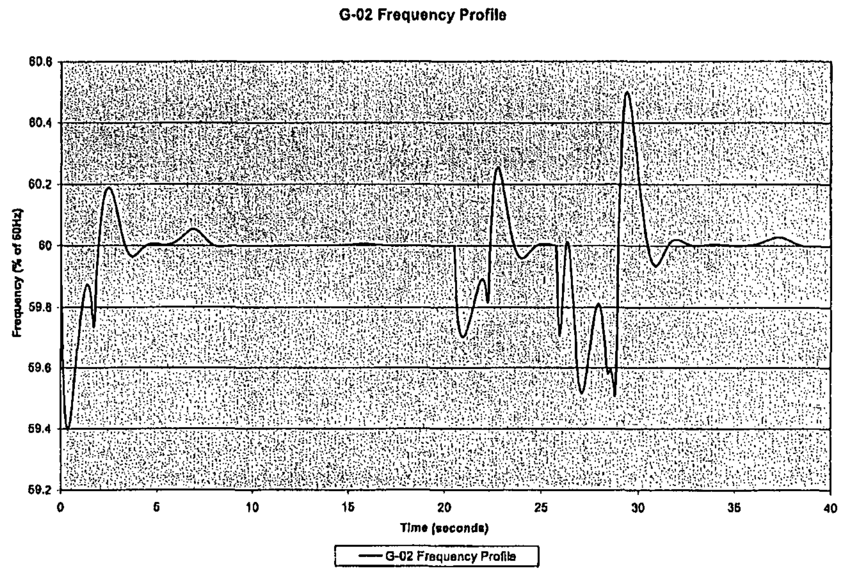
G-02 Voltage Profile, Plant operating DG Case 5 and study case DG Case 5-2



Section IV – EDG Transient Loading Analysis

Figure IV-44

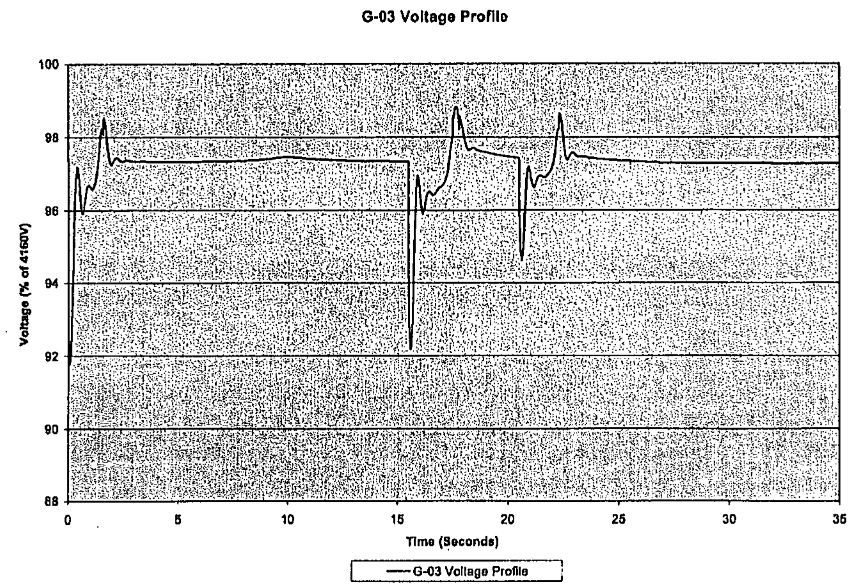
G-02 Frequency Profile, Plant operating DG Case 5 and study case DG Case 5-2



IV.7.02.6 Figures IV-45 to IV-52 provide a summary of the results of the EDG transient loading analysis for plant operating condition "DG Case 6." This case is based on the configuration that G-03 supplies Unit 1 B train safeguards loads and G-04 supplies Unit 2 B train safeguards loads. Unit 1 and Unit 2 are in mode 6 or defueled and the B03/B04 cross-tie is in-service and a LOOP occurs. Case 6 is evaluating the worst-case response in this alignment for both Unit 1 and Unit 2. Therefore, the common loads are conservatively considered to have a start signal as a result of an opposite unit event (e.g. SI).

Figure IV-45

G-03 Voltage Profile, Plant operating DG Case 6 and study case DG Case 6-1



Section IV – EDG Transient Loading Analysis

Figure IV-46

G-03 Frequency Profile, Plant operating DG Case 6 and study case DG Case 6-1

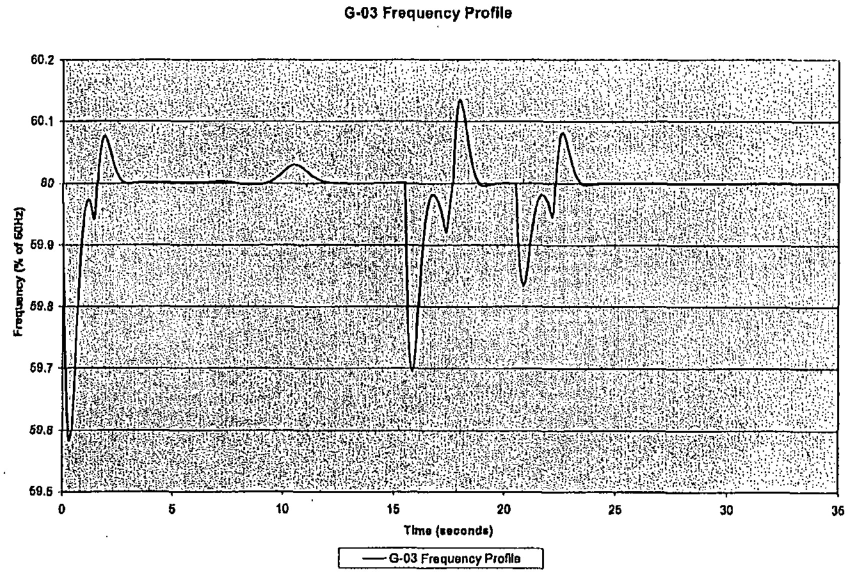


Figure IV-47

G-04 Voltage Profile, Plant operating DG Case 6 and study case DG Case 6-1

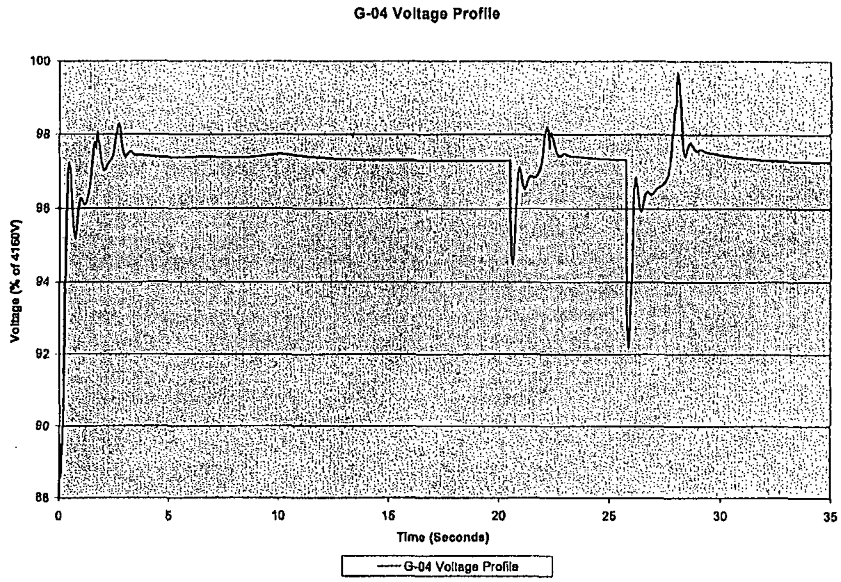


Figure IV-48

G-04 Frequency Profile, Plant operating DG Case 6 and study case DG Case 6-1

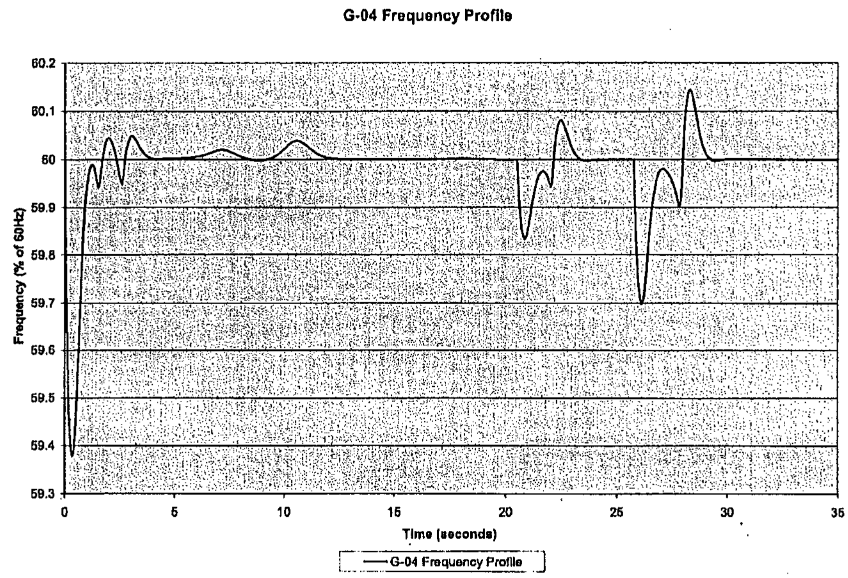


Figure IV-49

G-03 Voltage Profile, Plant operating DG Case 6 and study case DG Case 6-2

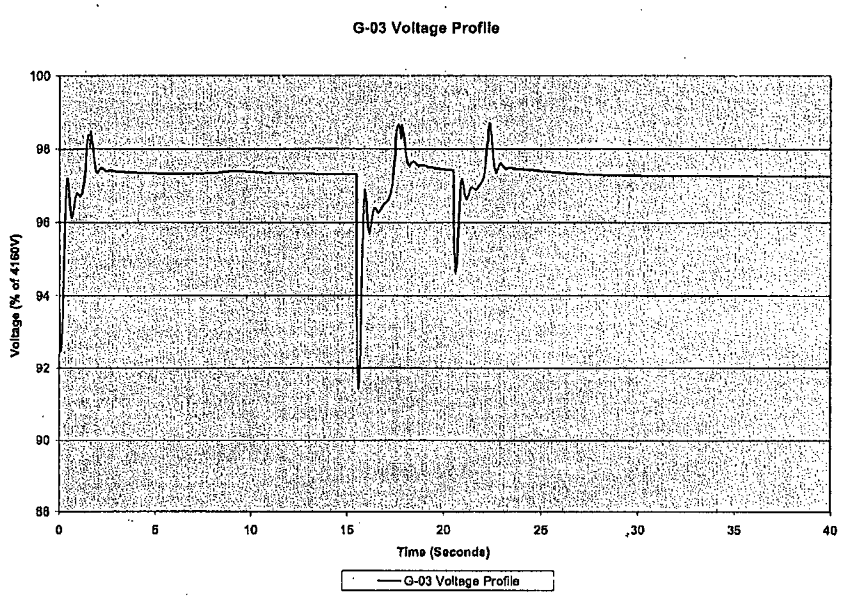


Figure IV-50

G-03 Frequency Profile, Plant operating DG Case 6 and study case DG Case 6-2

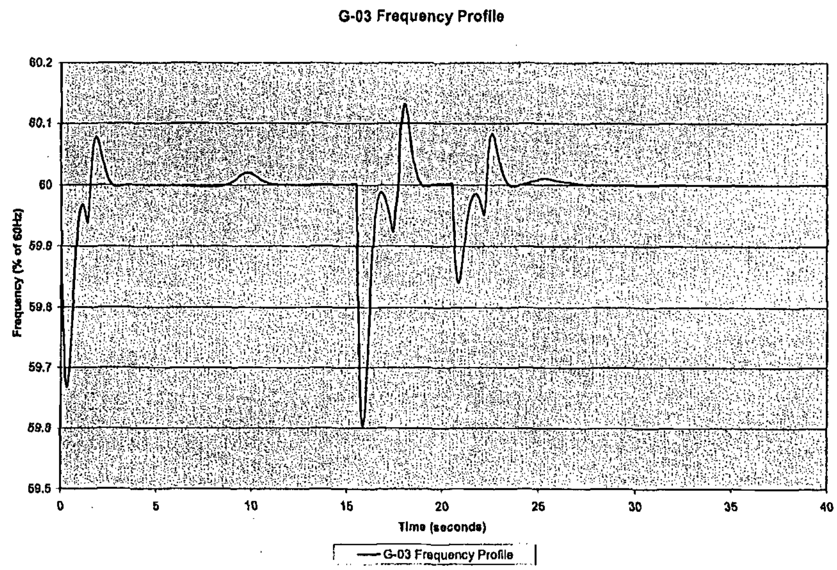
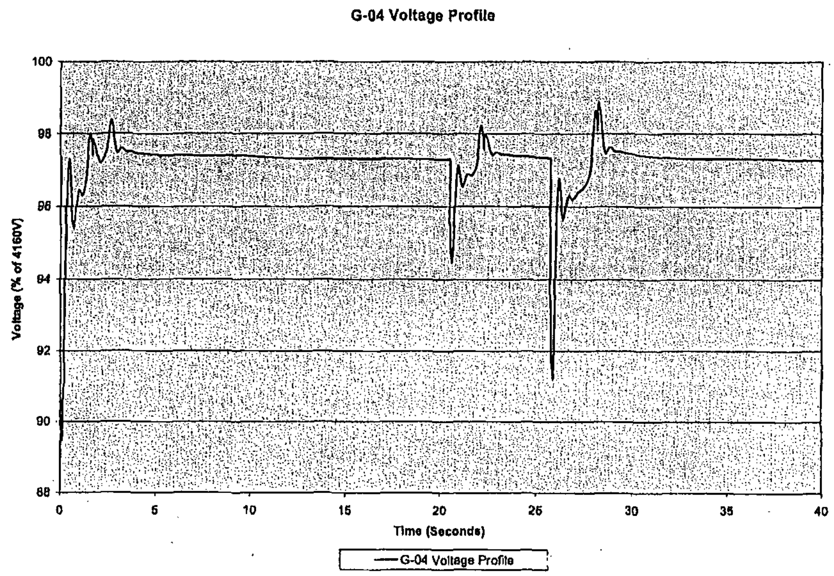


Figure IV-51

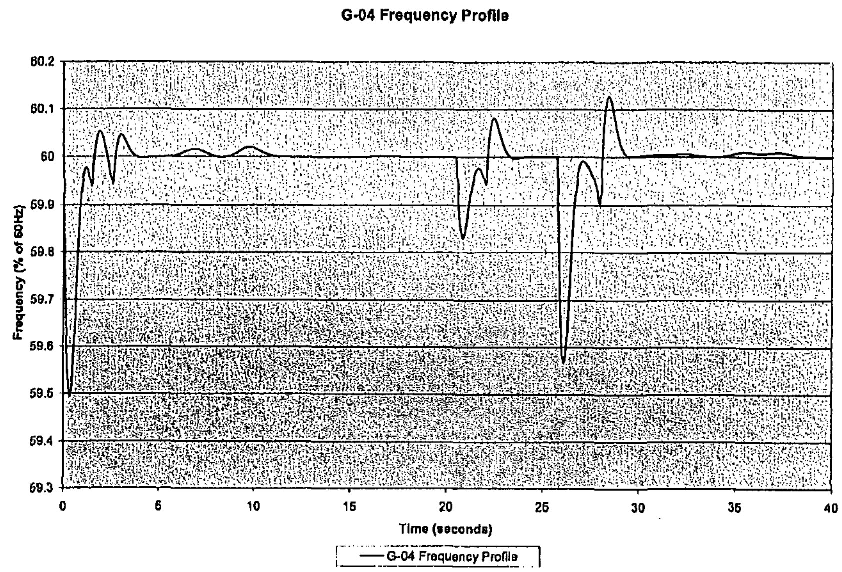
G-04 Voltage Profile, Plant operating DG Case 6 and study case DG Case 6-2



Section IV – EDG Transient Loading Analysis

Figure IV-52

G-04 Frequency Profile, Plant operating DG Case 6 and study case DG Case 6-2



IV.7.03 EVALUATION OF MOTOR ACCELERATIONS TIMES AND TIME TOLERANCES

A summary of the acceleration times for each individual motor for each plant operating scenario and associated study cases are provided in Attachment D1. The following table provides the worst-case acceleration time for each motor within a given service (SI, RHR, AFW, SW, CAF, CCW, and CS) by selecting the longest acceleration time from each motor service based on all the cases.

Motor	Worst Case Acceleration Time From Model Case Runs
SI	4.34sec
CCW	2.22 sec
RHR	0.94 sec
AFW	2.72 sec
SW	3.11 sec
CAF	14.90 sec
CS	2.15 sec

The results show that the acceleration time of the motors meet the requirements and satisfy Acceptance Criteria IV.3.04.

The following table shows a comparison of the acceleration time of the induction motors in comparison with the minimum time between the next consecutive sequenced load on the EDG. The results show that no additional analysis are required because there is no potential for overlap between the SI, RHR, AFW, and SW motors during the load sequence. However, there is a potential for overlapping load sequences between the start of the first and second CAF motor. However, the current analysis already evaluates the

EDG Voltage and Frequency Profiles From the Evaluation of the Impact on EDG Transient Loading Analysis Resulting from the AFW and AST Modifications

The following pages present EDG loading profiles from the evaluation of the EDG transient loading calculation. These profiles include auxiliary feedwater system or alternative source term modifications.

EDG Voltage Profile Review

Figures 8-1 to 8-2 provide a summary of the results of the EDG transient loading analysis for plant operating condition "DG Case 1." This case is based on the configuration that G-03 supplies both units B-train safeguards buses. Unit 1 is in mode 3 due to a unit trip because of a LOCA and a simultaneous LOOP. Unit 2 is in mode 6 or defueled and the B03/B04 cross-tie is in service. In this configuration, 2B-04 is providing power to 2B-03. The limitations are described in Calculation 2005-0007 for this case. The operating AFW pump is in the Unit with a LOCA/SI.

Figure 8-1: G-03 Voltage Profile, Plant operating DG Case 1 and study case DG Case 1-2

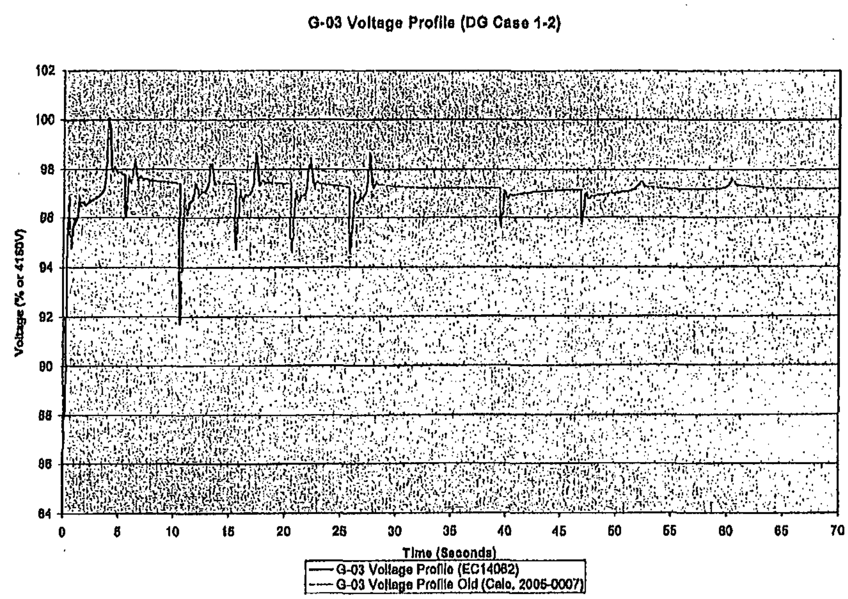
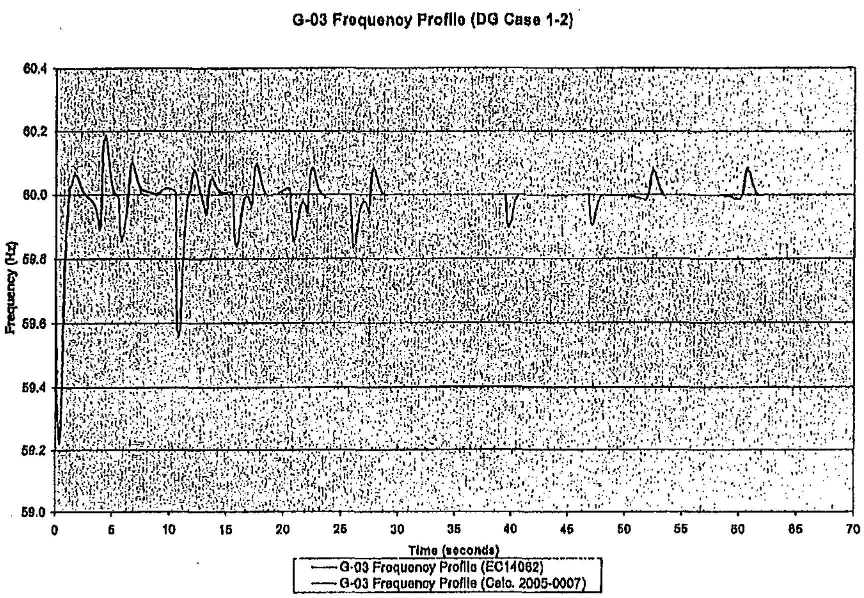


Figure 8-2: G-03 frequency Profile, Plant operating DG Case 1 and study case DG Case 1-2



EDG Voltage Profile Review

Figures 8-3 to 8-6 provide a summary of the results of the EDG transient loading analysis for plant operating condition "DG Case 2." This case is based on the configuration that G-01 supplies both units A-train safeguards buses. Unit 1 is in mode 3 due to a unit trip because of a LOCA and a simultaneous LOOP. Unit 2 is in mode 6 or defueled and the B03/B04 cross-tie is in service. In this configuration, 2B-03 is providing power to 2B-04. The limitations are described in Calculation 2005-0007. The operating AFW pump is in the Unit without a LOCA/SI.

Figure 8-3: G-01 Voltage Profile, Plant operating DG Case 2 and study case DG Case 2-2

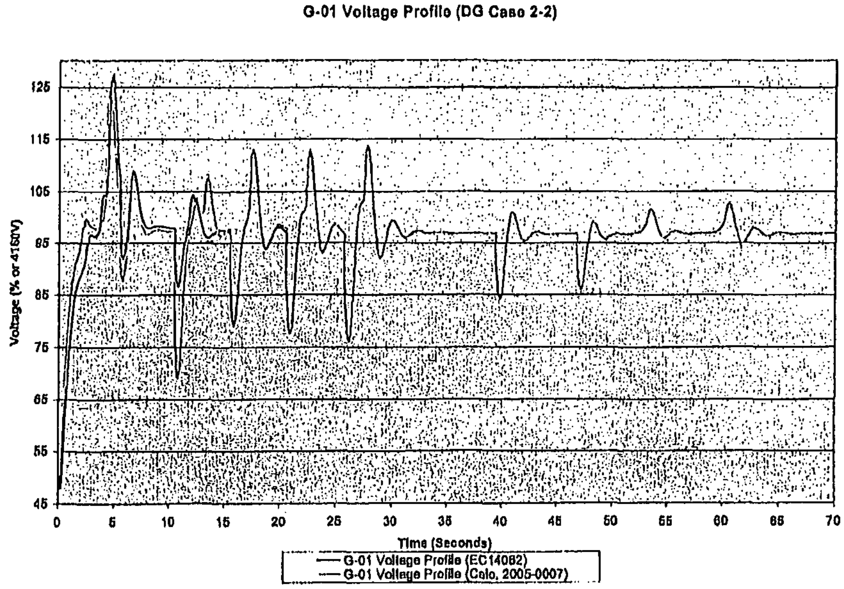
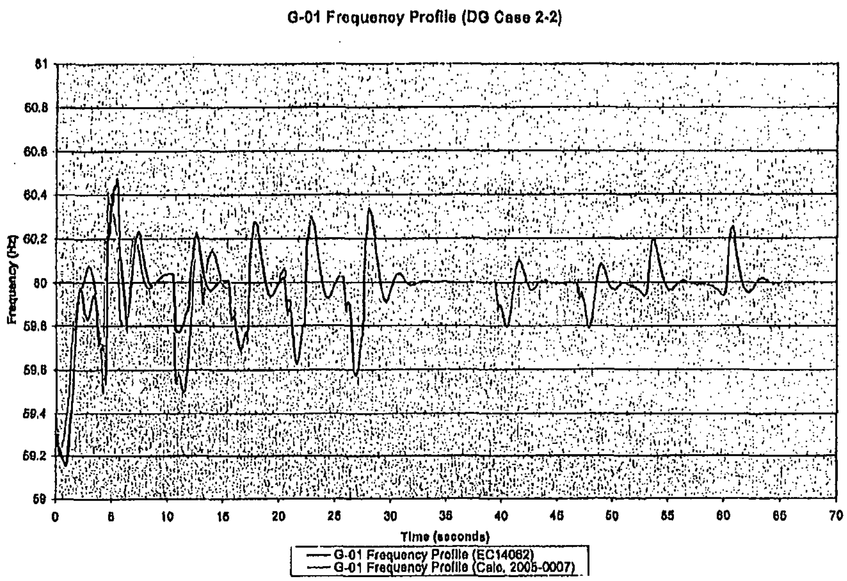


Figure 8-4: G-01 Frequency Profile, Plant operating DG Case 2 and study case DG Case 2-2



EDG Voltage Profile Review

Figure 8-5: G-01 Voltage Profile, Plant operating DG Case 2 and study case DG Case 2-3

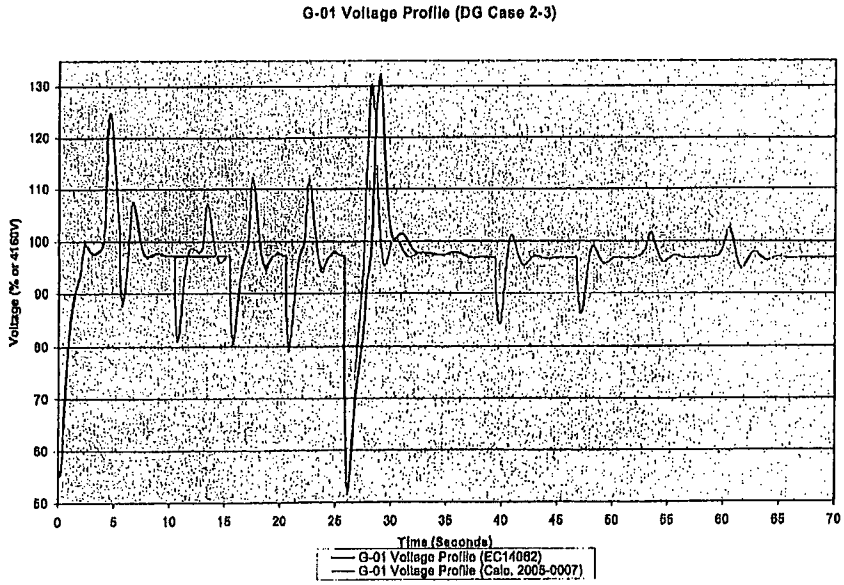
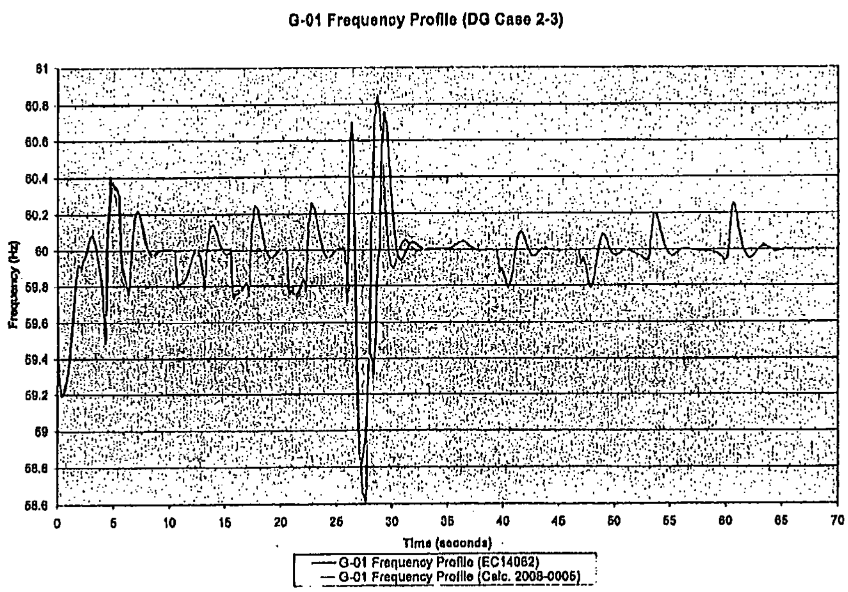


Figure 8-6: G-01 Frequency Profile, Plant operating DG Case 2 and study case DG Case 2-3



EDG Voltage Profile Review

Figures 8-7 to 8-8 provide a summary of the results of the EDG transient loading analysis for plant operating condition "DG Case 3." This case is based on the configuration that G-02 supplies both units A-train safeguards buses. Unit 2 is in mode 3 due to a unit trip because of a LOCA and a simultaneous LOOP. Unit 1 is in mode 6 or defueled and the B03/B04 cross-tie is in service. In this configuration, 1B-03 is providing power to 1B-04. The limitations are described in Calculation 2005-0007. The operating AFW pump is in the Unit with a LOCA/SI.

Figure 8-7: G-02 Voltage Profile, Plant operating DG Case 3 and study case DG Case 3-2

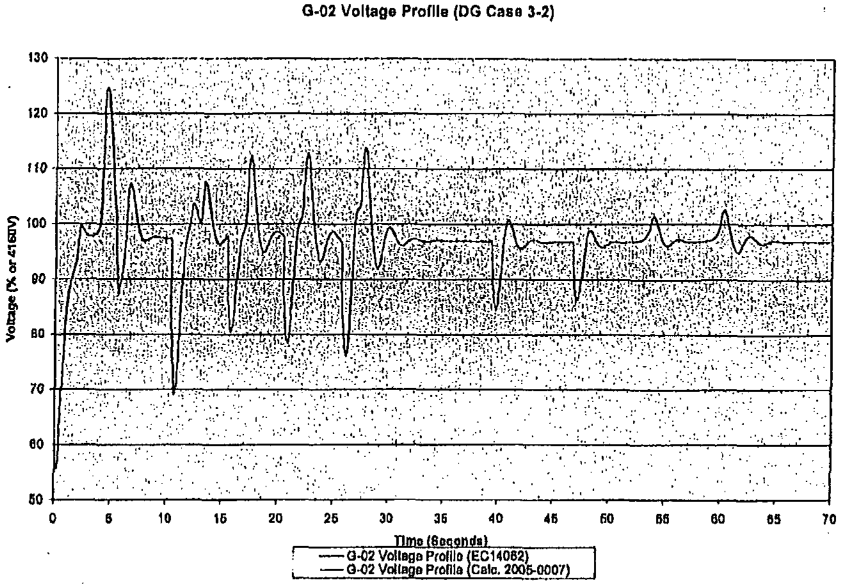
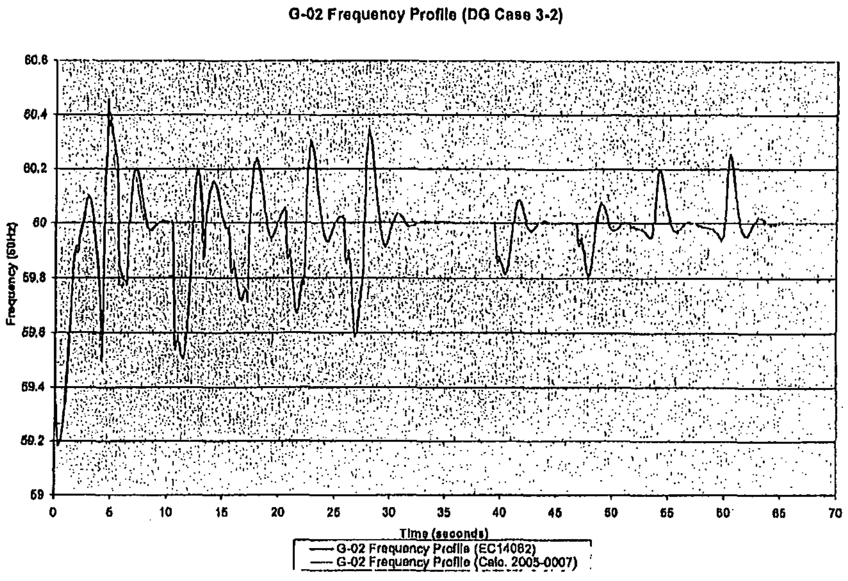


Figure 8-8: G-02 Frequency Profile, Plant operating DG Case 3 and study case DG Case 3-2



EDG Voltage Profile Review

Figures 8-9 to 8-12 provide a summary of the results of the EDG transient loading analysis for plant operating condition "DG Case 4." This case is based on the configuration that G-04 supplies both units B-train safeguards buses. Unit 2 is in mode 3 due to a unit trip because of a LOCA and a simultaneous LOOP. Unit 1 is in mode 6 or defueled and the B03/B04 cross-tie is in service. In this configuration, 1B-04 is providing power to 1B-03. The limitations are described in Calculation 2005-0007. The operating AFW pump is in the Unit without a LOCA/SI.

Figure 8-9: G-04 Voltage Profile, Plant operating DG Case 4 and study case DG Case 4-2

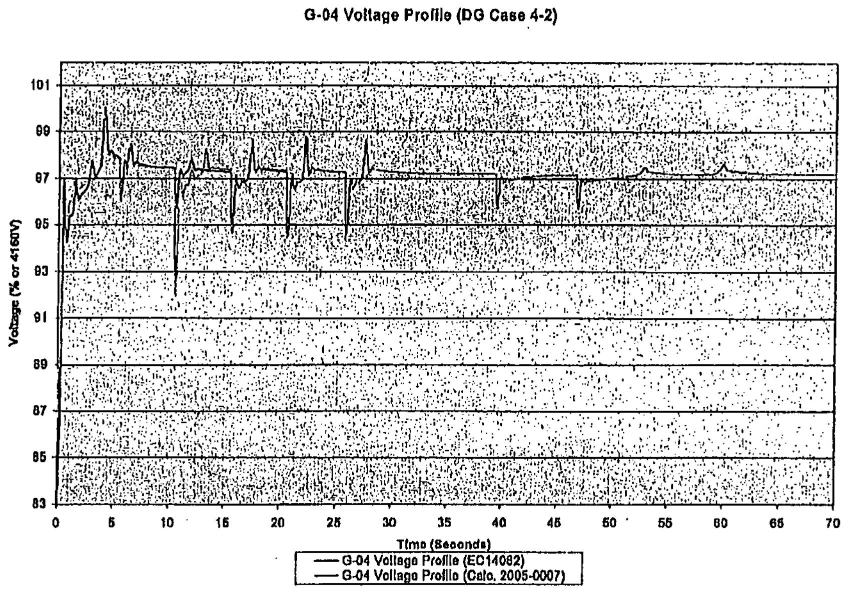
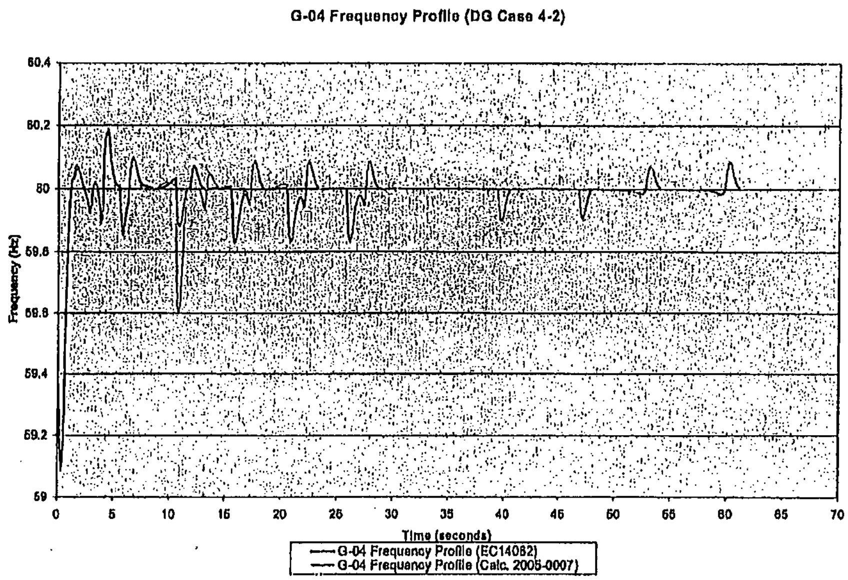


Figure 8-10: G-04 Frequency Profile, Plant operating DG Case 4 and study case DG Case 4-2



EDG Voltage Profile Review

Figure 8-11: G-04 Voltage Profile, Plant operating DG Case 4 and study case DG Case 4-3

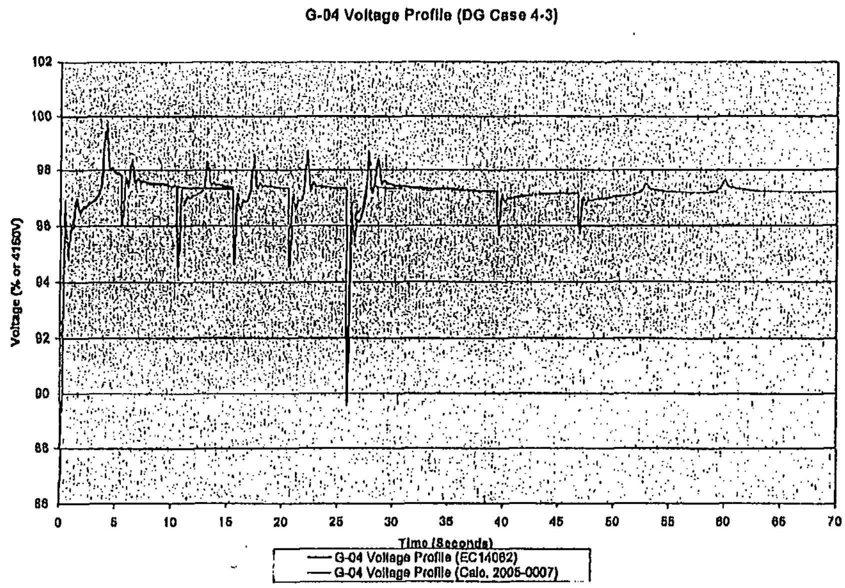
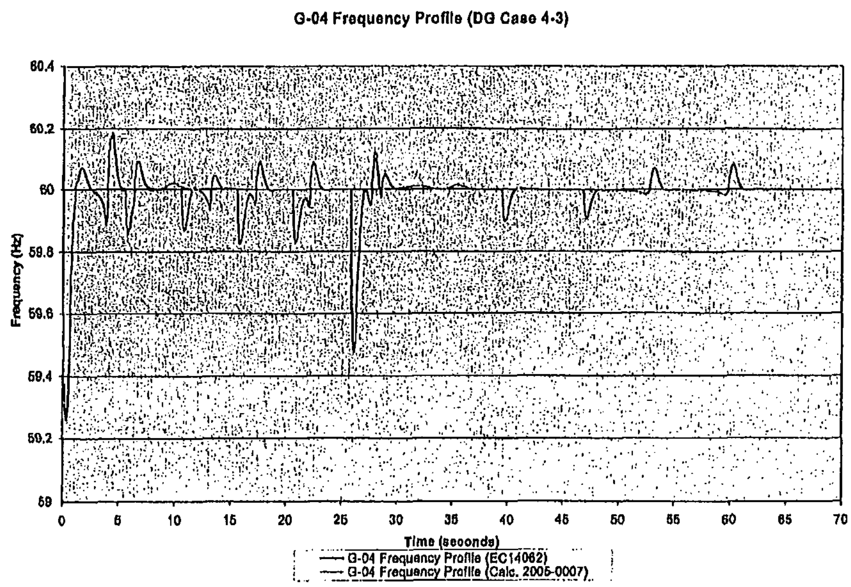


Figure 8-12: G-04 Frequency Profile, Plant operating DG Case 4 and study case DG Case 4-3



ENCLOSURE 3

NEXTERA ENERGY POINT BEACH, LLC
POINT BEACH NUCLEAR PLANT, UNITS 1 AND 2

LICENSE AMENDMENT REQUEST 261
EXTENDED POWER UPRATE
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION

ADDITIONAL INFORMATION - QUESTION 6 RESPONSE
CABLE AMPACITY CALCULATION

4 pages follow

Ampacity of AFW Pump Power Cables Routed in Conduit

1.0 Purpose and Scope

The purpose of this calculation is to determine the ampacity of AFW Pump Power cables ZB1A83-A and ZC2A68-A routed in conduit. The cables supply electric power from 4160-V Switchgear 1A06 and 2A05 to Motor Driven Auxiliary Feedwater Pumps (MDAFWP) 1P-53 and 2P-53, respectively. The conduits containing the fore-mentioned cables will be firewrapped. This calculation shall demonstrate the acceptability of these cables' ampacities with the derating caused by addition of the fire wrap. The addition of the fire wrap may be necessary to resolve a potential Appendix R condition that was previously documented in A/R 01131517 (Reference 8.2.4). As a result of this potential condition, a fire was postulated to spread between two fire zones. The installation of the fire wrap on the conduits will aid in the resolution of the potential condition documented in the A/R and will prevent any additional Appendix R issues.

2.0 Inputs

2.1 Ampacity Input Data

2.1.1. Conduit Ampacity Methodology Inputs

2.1.1.1. The base standard for development of the methodology for allowable ampacity is based on Article 310 of the National Electrical Code- Version 1965 (Reference 8.3.1).

2.1.1.2. Base Ampacity data is taken from Tables 310-12 and 310-14 of the code (Reference 8.3.1). These tables have been replicated in Attachment A to this calculation.

2.1.1.3. Correction factors for multiple conductors are taken from Note 8 to tables 310-12 through Table 310-15 of the code (Reference 8.3.1).

2.1.1.4. Correction factors for fire wrap addition are taken from NPC 2004-00619 (Reference 8.2.7).

2.2 Required Ampacity Methodology Input

The following information is used to determine the required ampacity and the required protective device settings for a given cable. This information is referenced in the Methodology section 4.2.

2.2.1. Load Types

Reference 8.2.2 is used to provide a general description of the load types present at Point Beach. Section 8.0.1 of Reference 8.2.2 also provides that consideration of load required ampacity is a requirement of the station.

2.2.2. Load Requirements

Reference 8.3.1 was used to provide the requirements for sizing of a cable relative to current carrying capacity.

3.0 Assumptions

3.1 Unvalidated Assumptions

None

3.2 Validated Assumptions

None

5.0 Acceptance Criteria

The Derated Ampacity (DA) of a cable in the worst case routing segment shall be 125% greater than the Required Ampacity of the cable (Reference 8.2.2, Section 8.0.1).

Motor current at nominal voltage of 4160V is 43 A. At 90% degraded voltage the motor amps is 47.8 A.

The required ampacity is motor rated full load amperes x 1.25, or 47.8 A x 1.25 = 59.75 A. This required ampacity is calculated at reduced voltage conditions.

6.0 Calculation

Cable ZB1A83-A is routed from Vital Switchgear 1A06 to the existing P38A Room to the new Motor-Driven Auxiliary Feedwater Pump Room for 1P53 and cable ZC2A68-A is routed from Vital Switchgear 2A05 through the P38B Room to the new Motor-Driven Auxiliary Feedwater Pump Room 2P53. This calculation determines the ampacity values for a room ambient temperature of 40°C per Reference 8.2.3.

6.1 Cable ZB1A83-A for 1P-053

Cable ZB1A83-A is a 3-1/C # 4/0 AWG 8-kV, copper, 90°C rated cable run in a 4" conduit. Per Reference 8.3.1, the base ampacity for 4/0 AWG cable is 211.5 A (based on 235 A times 0.9 for 40°C ambient).

Since cable ZB1A83-A has 3 conductors in one conduit, $ADF_{\text{Multiple Conductors}} = 1.0$.

Due to the installation of the 3M fire wrap, $ADF_{\text{Conduit Fire Wrap}} = 0.859$.

The conduits to be analyzed have fire stops installed, so $ADF_{\text{Conduit Fire Stop}} = 0.78$.

The cable ampacity is:

$$A = 211.5 * 1.0 * 0.859 * 0.78 = 142 \text{ A}$$

Based upon a review of Final Test Report for 350 HP Motors (Reference 8.2.8) at rating 4160V, the required ampacity for cable ZB1A83-A is 59.75 A, so the cable ampacity is acceptable.

6.2 Cable ZC2A68-A for 2P-053

Cable ZC2A68-A is a 3-1/C # 4/0 AWG 8-kV, copper, 90°C rated cable run in a 4" conduit. Per Reference 8.3.1, the base ampacity for 4/0 AWG cable is 211.5 A (based on 235 A times 0.9 for 40°C ambient).

Since cable ZC2A68-A has 3 conductors in one conduit, $ADF_{\text{Multiple Conductors}} = 1.0$.

Due to the installation of the 3M fire wrap, $ADF_{\text{Conduit Fire Wrap}} = 0.859$.

The conduit to be analyzed have fire stops installed, so $ADF_{\text{Conduit Fire Stop}} = 0.78$.

The cable ampacity is:

$$A = 211.5 * 1.0 * 0.859 * 0.78 = 142 \text{ A}$$

Based upon a review of Final Test Report for 350 HP Motors (Reference 8.2.8) at rating 4160V, the required ampacity for cable ZC2A68-A is 59.75 A, so the cable ampacity is acceptable.

7.0 Results and Conclusions

The cable ampacities for cables ZB1A83-A and ZC2A68-A are acceptable when their conduits have been wrapped with a 3-hour barrier. The operating conditions associated with the cables and the cable and raceway routes through the Vital Switchgear, PAB and Auxiliary Feedwater pump room have resulted in acceptable cable ampacity and room temperature has been deemed acceptable. The fire wrap will aid in resolving potential Appendix R issues associated with the cables.

This calculation has evaluated the anticipated maximum operating ampere load of the connected motor loads at degraded voltage conditions, and the ambient temperature room environments in which they are installed. The results of this ampacity calculation demonstrate that cables have adequate ampacity. The fire wrap can aid in resolving potential Appendix R issues associated with the cables and raceway routing.

ENCLOSURE 4

NEXTERA ENERGY POINT BEACH, LLC
POINT BEACH NUCLEAR PLANT, UNITS 1 AND 2

LICENSE AMENDMENT REQUEST 261
EXTENDED POWER UPRATE
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION

ADDITIONAL INFORMATION - QUESTION 6 RESPONSE
BREAKER COORDINATION CALCULATION

46 pages follow

1.1- Purpose

The purpose of this calculation is to determine the adequacy of the overcurrent relay settings and fuse sizes in providing coordination and protection for the 13.8 kV and 4.16 kV systems at Point Beach Nuclear Plant (PBNP). The protection of motors, transformers, and associated cables (within the scope of this calculation), is included in the adequacy review.

1. Purpose

The purpose of this calculation minor revision is to incorporate load changes into Base Calculation 2004-0009 resulting from modification EC 13401 and EC 13406.

These modifications add MDAFW (Motor Driven Auxiliary Feedwater) Pumps 1P-53 and 2P-53 to 4.16kV sources.

Minor Revision 2004-0009-002-A (Reference 8.2.4) and Minor Revision 2004-0009-002-B (Reference 8.2.5) have been reviewed and the modifications as described above have been determined to not impact this minor revision.

The calculation minor revision will update Attachment A (Protection and Coordination Plots), Attachment B (relay setting calculations), Attachment C (tabulation of relay settings) and Attachment D (applicable references). A description of the modification implemented in this minor revision is as follows:

1.2 Scope

The scope of this calculation is limited to the review of the overcurrent relaying coordination and protection provided for the 13.8 kV and 4.16 kV buses. Review of all overcurrent relay settings and fuse sizes associated with the feeder, source, and bus tie breakers of the 13.8 kV Buses H - 01, H - 02, H - 03, H - 08, H - 09 and H - 504, and of the 4.16 kV Buses 1A - 01, 1A - 02, 1A - 03, 1A - 04, 1A - 05, 1A - 06, 1A - 07, 2A - 01, 2A - 02, 2A - 03, 2A - 04, 2A - 05, 2A - 06 and 2A - 07 is included in the scope of this calculation. In addition, the review of the settings for the overcurrent relays on the high side of the UATs and HVSATs is also included in the scope of this calculation.

EC 13401

This modification adds MDAFW Pump 2P-53 to 4.16 kV Bus 2A-05. New CTs and relaying are also added.

The following electrical loads were added to power sources by these modifications:

1.1.1. Added Load – MDAFW Pump 2P-53 to 4.16 kV Bus 2A-05 Breaker 2A52-68

1.1.2. The following protective devices were provided for pump 2P-53 – CT and Relaying associated with 2P-53 addition:

1.1.2.1. 2A52-68 New 100/5 CTs associated with 2P-53 Phase Overcurrent Relay

1.1.2.2. New West. COM-5 51/50A,B,C/A52-68 Phase Overcurrent Relay

1.1.2.3. New 2A52-68 GCT associated with 2P-053 Ground Overcurrent Relay

1.1.2.4. New West. ITH 50G/A52-68 Ground Overcurrent Relay

EC 13406

This modification adds MDAFW Pump 1P-53 to 4.16 kV Bus 1A-06. New CTs and relaying are also added.

The following electrical loads were added to power sources by these modifications:

1.2.1. Added Load – MDAFW Pump 1P-53 to 4.16 kV Bus 1A-06 Breaker 1A52-83

1.2.2. The following protective devices were provided for pump 1P-53 – CT and Relaying associated with 1P-53 addition:

1.2.2.1. 1A52-83 New 100/5 CT's associated with 1P-53 Phase Overcurrent Relays

1.2.2.2. New ABB 51Y/A53-83 Phase Overcurrent Relay

1.2.2.3. New ABB 50D/A52-83 Phase Overcurrent Relay

1.2.2.4. New ABB 49/A52-83 Phase Overcurrent Relay

1.2.2.5. New 1A52-83 GCT associated with 1P-53 Ground Overcurrent Relay

1.2.2.6. New ABB GKT/A52-83 Ground Overcurrent Relay

2. Design Inputs

The following design inputs and revision to the existing inputs in the Base Calculation are required for the relay setting calculations:

2.1. Section 6.0 of Base Calculation 2004-0009 (Reference 8.2.1) will be revised to read as follows:

"The motor rated voltage for all medium voltage motors except the circulating water pump motors and the MDAFW pumps is 4000 V. The motor rated voltage for the circulating water pump motors {5.2.1} and the MDAFW pump motors {5.8.15 and 5.8.16} are 4160V."

"The Westinghouse CO - 5, COM - 5, CO - 6, CO - 8, COV - 8, CO - 9 and ITH relays are

electromechanical {5.5.1, 5.5.6}. The ABB (BBC) ITE - 51L, and the ABB 49, 50D, 51E, 51L, 51Y and GKT relays are static {5.5.2}."

2.2. Section 6.11 of Base Calculation 2004-0009 (Reference 8.2.1) will be revised in the following manner to add a line item to the existing table for motor data/relaying associated with MDAFW Pumps 2P-53:

Service	Cubicle No.	Hp, kVA, or MVA or 2000 - hr rating, power factor	Circuit FLC	Circuit LRC, Safe Stall, Starting Time or X''_{dv} ,X'_{dv},X_{dv}, T''_d, T'_d, I_F, I_{Fg}	Xfmr Z, Tap, Secondary Voltage, Winding Connect	Phase CT Ratio	Phase Overcurrent Relays, Type, Style #, Existing Settings, Time Tol.*	Cable Size / Rated & Short Circuit Temperatures / Conductor Material
Motor Driven Auxiliary Feedwater Pump 2P-53	2A52 - 68	350 hp {5.8.15}	43 A {5.8.15}	5.58 x 43A = 239.94 A, {5.8.15} 24 sec for Hot Stall, 25 sec for Cold Stall, 3 sec start time at 76.9%V and 100% Load, 100%V, NA {5.8.15}		100 - 5 A {5.8.15}	COM - 5 289B355A12 Tap 2.5 (2-6), TD ~5, HD Inst 4, Inst 24 (20-80) {5.4.1}	3-1/C-4/0 AWG, 90 & 200 °C, Conduit, Tray {5.8.15}

2.3. Section 6.6 of Base Calculation 2004-0009 will be revised in the following *manner to add a line item to the existing table for motor data/relaying* associated with MDAFW Pump 1P-53:

Service	Cubicle No.	Hp, kVA, or MVA	Circuit FLC	Circuit LRC, Safe Stall, Starting Time or X''_{dv}, X'_{dv}, X_{dv}, T''_{d}, T'_{d}, I_F, I_{Fg}	Trf Z / Winding Connect	Phase CT Ratio	Phase Overcurrent Relays /Type/ Style # / Required Settings	Cable Size / Rated & Short Circuit Temperatures / Ampacity
Motor Driven Auxiliary Feedwater Pump 1P-53	1A52 - 83	350 hp (5.8.16)	43 A (5.8.16)	5.58 x 43A = 239.94 A, (5.8.16) 24 sec for Hot Stall, 25 sec for Cold Stall, 3 sec start time at 76.9%V and 100% Load, 100%V, NA (5.8.16)		100 - 5 A (5.8.16)	ABB – 51Y 443T2340 Tap 4 (4-12), TD 10 ABB - 50D 468T1775 Inst 24 (8-80) Delay 0.01 s ABB - 49 414A0043 Tap 2.5, Time 60 s @ 2X Alarm Only (5.4.1)	3-1/C-4/0 AWG, 90 & 200 °C, Conduit, Tray, Duct Bank (5.8.16)

2.4. Section 6.24 of Base Calculation 2004-0009 will be revised to read as follows:

"The Motor Acceleration Curve Data for the new 4.16 kV MDAFW Pump is shown in Engineering Changes EC 13401 and EC 13406 {5.8.15 and 5.8.16}".

2.5. Section 6.26 of Base Calculation 2004-0009 will be revised to add a sentence which reads as follows:

"The relay manufacturers for MDAFW Pumps 1P-53 and 2P-53 as listed in Attachment C are taken from References {5.8.15 and 5.8.16}".

2.6. Section 6.32 of Base Calculation 2004-0009 will be revised to include line items to read as follows:

Relay	Test Upper Limit (+4%) {5.8.15}	Test Time (3x)	Test Lower Limit (-4%) {5.8.15}	Source
MDAFW Pump 2P-53 51/50A,B,C/A52-68 COM - 5	21.9 s	20.9 s	19.9 s	Minor Revision 2004-0009-002-E Plot A57
MDAFW Pump 1P-53 51Y/A52-83 50D/A52-83 49/A52-83	6.1 s	5.8 s	5.5 s	Minor Revision 2004-0009-002-E Plot A58

2.7. Section 6.34 of Base Calculation 2004-0009 will be revised to include the following statement regarding the MDAFW Pumps 1P-53 and 2P-53:

"The MDAFW Pumps 1P-53 and 2P-53 are classified as safety-related. Per EC 13401 and EC 13406 {5.8.15 and 5.8.16}."

3. <u>Assumptions</u>

3.1. Validated Assumptions

Our review of the base calculation validated assumptions indicate that none have an adverse effect on this minor calculation revision.

3.2. Unvalidated Assumptions

There are no unvalidated assumptions associated with this calculation minor revision.

5. Acceptance Criteria

5.1. Acceptance criteria 3.1.1, 3.1.2, 3.2.1, 3.2.3, 3.2.4 and 3.2.5 of the Base Calculation 2004-0009 for relay settings were used in this calculation minor revision.

3.1 General Criteria

3.1.1 The motor overcurrent relay high set instantaneous overcurrent element setting must be high enough to prevent spurious trips of the instantaneous element on motor starting. See Section 2.1.3.4 of this calculation.

3.1.2 The motor time overcurrent relay time dial setting must be selected to prevent a spurious trip of the time overcurrent unit during motor starting. See Sections 2.1.3.5 through 2.1.3.8 of this calculation.

3.1.3 The time overcurrent pickup of the transformer feeder high side relay must not exceed the maximum value of 400 % of the transformer self cooled rating indicated by the National Electrical Code {5.1.14}.

The rating of a transformer high side fuse must not exceed the maximum value of 300 % of the transformer self cooled rating indicated by the National Electrical Code {5.1.14}. See Section 2.1.4.1 of this calculation.

3.1.4 The time - current curve for a transformer high side overcurrent relay (or fuse), should generally lie below the transformer's adjusted short circuit withstand curve. Some crossover in the overload region is permissible. See Section 2.1.4.8 of this calculation.

3.1.5 The time - current curve for a relay at a normal or alternate feed breaker for a medium voltage bus must be selected so that the relay curve lies below the upstream transformer's short circuit withstand capability curve. See Section 2.1.4.9 of this calculation.

3.1.6 A transformer high side relay instantaneous pickup setting, or high side fuse rating, must be high enough to avoid tripping the transformer during energization. See Section 2.1.4.5 of this calculation.

3.1.7 The diesel generator and gas turbine generator overcurrent relays must eventually trip for a short circuit fed from the generator when the rapid decay of short circuit current from a generator is accounted for. See Section 12.3.3 of IEEE 242 - 2001 {5.1.1}.

3.1.8 The diesel generator and gas turbine generator overcurrent relays must provide short circuit protection for the generator. See Section 12.5.3 of IEEE 242 - 2001 {5.1.1}.

3.1.9 The pickup of the phase overcurrent relay at the main breaker for a bus, or at the tie breaker between two buses, must be set high enough to carry the maximum load. See Section 2.1.6.1 of this calculation.

3.2 Licensing Related Criteria

3.2.1 Protective devices for all 4160 V and 480 V load center (switchgear) feeders shall coordinate with the applicable source protective device {5.1.12}.

For the 13.8 kV system, all load breaker relays shall coordinate with the relays for the incoming feeds from the HVSATs. This criterion satisfies the FSAR requirement {5.1.13} that a single fault will not result in a loss of power to both units.

Full coordination is not required between two protective devices in a single series path (for example, at opposite ends of a cable, or on the primary and secondary of a transformer), where opening either breaker or fuse results in the loss of the same load. Both devices must coordinate with all upstream and downstream protective devices.

An additional requirement for the setting of the bus normal feed, alternate feed, or tie breaker phase overcurrent relay is the following. The bus relay must not operate before the motor overcurrent relay, when the largest motor on the bus has started, and is accelerating to rated speed, while the bus is fully loaded {5.1.8}.

3.2.2 In order to avoid tripping a transformer high side relay for a low side fault, the instantaneous pickup must be set above the maximum value of the transformer through fault current. Alternatively, a definite time delay can be used to allow the short circuit current dc offset to decay before relay actuation. See Sections 2.1.4.2 and 2.1.4.3 of this calculation. This requirement is necessary to ensure coordination between the 480 V load center switchgear breakers and the transformer high side relays, as indicated in Section 3.2.1.

3.2.3 The protective devices are required to provide short circuit protection for both the safety - related and non - safety - related feeder cables, and the containment penetrations. The protective device curve must lie below the thermal damage curve of the cable on the coordination plot {5.1.11}.

If the cable is downstream of the protective device, then the damage curve must be based on the capability of only one conductor per phase of a multi - conductor feed. If the cable is upstream of the protective device, then the capability should be based on the capability of all of the conductors in a multi - conductor feed. See Section 2.1.5.2.

3.2.4 The settings for safety - related motor overcurrent relays shall be established to allow the motor to start throughout its allowable voltage range to support its safety - related design function as discussed in the FSAR {5.1.9, 5.1.10}.

3.2.5 The relay settings must satisfy the Appendix R coordination requirements for associated circuits with common power supplies. For the 13.8 kV and 4.16 kV buses which supply safe - shutdown loads (see Section 1.2), the feeder protective devices for non - safe - shutdown loads are required to coordinate with the source protective device. The feeder protective devices for safe - shutdown loads are also required to coordinate with the source protective device if multiple safe shutdown loads fed from one source are credited for different fire areas, or are fed from cables which are run through different fire areas {5.8.1 & 5.8.2}.

3.2.6 The overcurrent relays for the safety injection pump motors must coordinate with the overcurrent relays for the diesel generators. This criterion is one specific result of the Appendix R coordination requirements {5.8.1 & 5.8.2}.

3.2.7 The safety injection pump motor 1P - 015A overcurrent relay must coordinate with the upstream Bus 1A - 03 protective devices. This criterion is one specific result of the Appendix R coordination requirements. Note that the overcurrent relays for safety injection pump motors 1P - 015B, 2P - 015A and 2P - 015B are not required to coordinate for Appendix R because the upstream supply is not a credited safe shutdown power supply {5.8.1, 5.8.2}.

4.0 Assumptions

4.1 Unvalidated Assumptions

4.1.1 None

4.2 Validated Assumptions

4.2.1 It is assumed, when the conductor material type is not available, that the conductor material is copper.

Basis: This assumption is justified in that a review of CARDS {5.8.3}, field walkdowns, and cable specifications {5.8.6, 5.8.7, 5.8.8} shows that the majority of cables used at PBNP are copper. Therefore, this assumption is reasonable.

4.2.2 It is assumed for generator G - 05, that the ratio of I_F / I_{Fg}, which is the ratio of field current with voltage regulator action included, to the field currrent at no load, is in the range from a minimum of 1.25 to a maximum of 1.8.

Basis: See Table 7.2 of "Power System Control and Stability" {5.9.4}. This table provides typical exciter ceiling voltages for various exciter response ratios. The sustained (steady state) fault current is proportional to the ratio of the maximum exciter voltage to the nominal exciter voltage. Therefore I_F / I_{Fg} is equivalent to the per unit exciter ceiling voltage.

The excitation for Generator G - 05 is provided by a small shaft - driven dc generator, and no SCR's are provided. Therefore it can be concluded that this generator has a conventional exciter {5.3.14}.

The relay action will be evaluated for the two extreme values of 1.25 and 1.8 provided for conventional exciters.

4.2.3 It is assumed that emergency diesel generators G - 01, G - 02, G - 03 and G - 04, the gas turbine generator G - 05, and main generators 1TG - 01 and 2TG - 01 will have a maximum pre-fault voltage of 105 % of rated voltage.

Basis: Procedure OP 2A, "Normal Power Operation", Attachment H "345 kV Voltage Control", {5.11.17} indicates that the maximum operating voltage of the 19 kV main generator is 19.9 kV, or 104.7 % of 19 kV.

Procedure OI 110, "Gas Turbine Operation", Section 3.25, {5.11.18} indicates that the maximum operating voltage of the 13.8 kV gas turbine generator is 14.4 kV, or 104.3 % of 13.8 kV.

Procedures AOP - 22, Unit 1 {5.11.19}, and AOP - 22, Unit 2 {5.11.20}, indicate that the maximum operating voltage of the emergency diesel generators is 4300 V, or 103.4 % of 4160 V.

NEMA MG 1 {5.1.15}, states that the maximum continuous voltage rating for synchronous generators is 105 % of rated voltage.

It is conservative to model the generators at their maximum voltage to establish the maximum fault current for the time current curves.

4.2.4 It is assumed that:

1) The motor acceleration and thermal limit curve SGV0421824 (given on page 4 of Attachment C of Calculation 2001 - 0033 {5.2.1}), for operation starting from the motor rated temperature, applies to the steam generator feedwater pump motor with serial number L&M77P319, which is not listed on the data sheet, as well as to the four motors which are listed on the data sheet (serial numbers L&M77P320, L&M77P321, L&M77P322 and 1S84P737).

2) The motor acceleration and thermal limit curve SGV0421823 (given on page 5 of Attachment C of calculation 2001 - 0033 {5.2.1}), for operation starting from the ambient temperature, applies to the steam generator feedwater pump motor with serial number L&M77P319, which is not listed on the data sheet, as well as to the four motors which are listed on the data sheet (serial numbers L&M77P320, L&M77P321, L&M77P322 and 1S84P737).

Basis: The nameplate data for the steam generator feedwater pump motor with serial number L&M77P319 is the same as the nameplate data for the motors with serial numbers L&M77P320, L&M77P321 and L&M77P322. All 5 motors were purchased and manufactured at approximately the same time.

4.2.5 It is assumed that generators G - 01, G - 02, G - 03, G - 04 and G - 05 are able to thermally withstand 3 times rated current for 10 seconds.

Basis: In "Application Aspects of Generator and Excitation System for Process Plants", it is stated that "Another important criterion to be applied to the generator and excitation system is that they must deliver a sustained short circuit current of 3.0 per unit for 10 seconds" {5.9.6, page 704}.

Paragraph MG 1 - 22.41, "Maximum Momentary Overloads", of NEMA Standard MG 1 - 1966 {5.1.15}, specifies that a synchronous generator shall be capable of carrying 150 % of rated current for 1 minute. The value of 150 % for 1 minute corresponds to an I^2t capability of 135 (per unit current)^2 seconds.

MG 1 - 1987 {5.1.16} specifies that a synchronous generator with a speed greater than 1800 rpm shall be capable of carrying 130 % of rated current for 1 minute. The requirement of 150 % of rated current for 1800 rpm or less is retained from the 1966 standard. The generators G - 03 and G - 04 have a speed of 900 rpm {5.2.1}.

Utilizing the capability of three times rated current for 10 seconds, corresponding to an I^2t capability of 90 (per unit current)^2 seconds, is therefore conservative with respect to the industry standards for thermal capability.

4.2.6 It is assumed that the taps for non - safety related transformers X - 27, X - 48, X - 500, X - 07, X - 704, XL - 45 and XL - 46 are set to their nominal tap position.

Basis: Similar transformers in the system are set between 0% (nominal) and +5% of the transformer primary voltage, which would provide a voltage reduction on the secondary side. Therefore, it is conservative to assume the transformer tap settings are set at their nominal tap position because this would provide a higher pre-fault voltage and provide the worst-case fault current on the secondary side of the transformer.

4.2.7 It is assumed for the purposes of this calculation that the UATs use a tap setting corresponding to a 5 % boost of the secondary side voltage (corresponding to 95 % of the primary turns).

Basis: The UAT primary side current is equal to the UAT secondary side current divided by the turns ratio of primary to secondary voltage. The maximum secondary side voltage boost for the UAT will result in the lowest turns ratio, and therefore the highest UAT primary side current for the same UAT secondary side current. The maximum secondary side voltage boost will therefore result in the fastest operating time for the UAT high side relay, and therefore the minimum coordination time with the low side bus feed relay, and is therefore conservative.

The maximum through fault current is reduced if the boost is reduced, since the secondary side prefault voltage will be lower.

It should be noted that the purpose of this assumption is to justify not revising this calculation for a change in the UAT tap setting if in the future the boost of 5 % is reduced.

4.2.8 It is assumed that the negative timing tolerance of the CO - 9 relay for the feed to transformers X - 65, X - 66 and X - 72 is 20 %.

Basis: The other CO - 9 relays at the H Buses have positive and negative timing tolerance magnitudes of about 5 %. See Sections 1ao, 1ap and 1aq of Attachment B. Therefore it is conservative to use a value of 20 % for the relay timing tolerance in order to evaluate the coordinating time interval.

The A/R No. 01039716 has been written to develop a relay calibration sheet for the relays 51 / 50 A,B,C / H52 - 23. This relay calibration sheet will incorporate a new timing tolerance magnitude of 5 %.

4.2.9 It is assumed that the instantaneous settings of 480 V breakers PP - 30 Main, PP - 35 Main and B00 - 511A are at the maximum value of 10 X.

Basis: Since these breakers are downstream devices in the coordination plots, a maximum value will result in a minimum coordination margin, and is therefore conservative.

4.2.10 It is assumed for transformers X - 07 and X - 704 that the transformer impedance is equivalent to the typical value stored in the ETAP library.

Basis: The typical transformer parameters in the ETAP library have been derived from accepted industry standards for power transformers. The slight difference between the actual and the typical values will not affect the results and conclusions of the calculations.

4.2.11 It is assumed that the generators G - 01, G - 02, G - 03 and G - 04 have a minimum operating voltage of 4050 V. This assumption is used to calculate the minimum decrement current without field forcing, and the minimum sustained field forcing current.

Basis: The procedures AOP - 22 for unit 1 and AOP - 22 for unit 2 indicate that the minimum operating voltage for the generators G - 01, G - 02, G - 03 and G - 04 is 4050 V {5.11.19, 5.11.20}.

4.2.12 It is assumed that the generator G - 05 has a minimum operating voltage of 13800 V. This assumption is used to calculate the minimum decrement current without field forcing, and the minimum sustained field forcing current.

Basis: The procedure OI 110 indicates that the minimum operating voltage for the generator G - 05 is 13800 V {5.11.18}.

4.2.13 It is assumed that the generators G - 01, G - 02, G - 03, G - 04 and G - 05 are operating unloaded at the time of a short circuit without field forcing.

Basis: If the generator is operating unloaded, the voltages behind the subtransient and transient reactances will be minimum values for a given terminal voltage, resulting in minimum subtransient and transient components of fault current. The steady state component of the fault current will also be a minimum value since the field current will be equal to the no load field current for the given terminal voltage. The steady state component of the current will then be equal to the terminal voltage divided by the synchronous reactance. See Section 2.1.7.

4.2.14 It is assumed that the maximum load fed by the HVSAT is 62 MVA. This assumption is used to evaluate the adequacy of the pickup of the HVSAT low side overcurrent relay when one of the HVSATs is out of service. See Section 2.1.6.1.

Basis: There is no calculation available which determines the maximum loading of the HVSATs 1X - 03 and 2X - 03 when one of the transformers is out of service (tracked under Action Item 00458756). Attachments B (measured load) and D (connected load) of Calculation 2004 - 0001 {5.2.2}, are therefore used to estimate the maximum load for most of the plant services. The transformer rating is used for transformers X - 704, X - 45, XL - 45 and XL - 46.

As described in the basis for the assumption in Section 4.1.20 of Calculation 2004 - 0001 {5.2.2}, the measured values represent the normal running condition of both units at PBNP. The maximum measured values were used to provide the highest loading based on actual plant operating experience.

It is reasonable to expect that the measurements provide a conservative value of the total load during actual plant operation due to the large number of readings taken throughout the year (approximately 80 measurements between March and August plus one measurement for the month of November). Although some individual services may have a higher maximum load which has not been recorded in the measurements, the total load will not be greater since the maximum loads for all services will not occur at the same time.

Additional conservatism is provided by using the full connected load or nameplate rating with no demand factor for transformers where no measurements are available.

The load magnitudes are conservatively summed together without taking into account the load power factors.

The maximum load is determined for the condition when both units are operating in Mode 1. The accident loads are not considered. Ignoring the accident loads is acceptable for this analysis since the steam generator feedwater pumps are tripped on a safety injection signal. See Section 6.4.03 of Calculation 2004 - 0001 {5.2.2}. The total load of the two 5000 hp steam generator feedwater pumps for a unit is greater than the accident load.

Bus	Breaker	Service	Load	Basis
H - 01	H52 - 11	Transformer X - 08	831 kVA	2004 - 0001, Section 4.1.20, {5.2.2}
H - 01	H52 - 14	Transformer X - 48	413 kVA	2004 - 0001, Attachment B, page 3, Maximum Peak, {5.2.2}
H - 01	H52 - 16	Transformer X - 27	789 kVA	2004 - 0001, Attachment B, page 3, Maximum Peak, {5.2.2}
H - 01	H - 504 - 02B	Transformer X - 500	127 kVA	2004 - 0001, Attachment D, page 61, Connected {5.2.2}
1A - 01	1A52 - 02	Station Service Transformer 1X - 11	790 kVA	2004 - 0001, Attachment B, page 1 Maximum, {5.2.2}
1A - 01	1A52 - 04	Reactor Coolant Pump 1P - 001A	4394 kVA	2004 - 0001, Attachment B, page 1 Maximum, {5.2.2}
1A - 01	1A52 - 05	Steam Generator Feedwater Pump 1P - 028A	4198 kVA	2004 - 0001, Attachment B, page 1 Maximum, {5.2.2}
1A - 01	1A52 - 06	Circulating Water Pump 1P - 030A	1746 kVA	2004 - 0001, Attachment B, page 1 Maximum, {5.2.2}
1A - 01	1A52 - 07	Condensate Pump 1P - 025A	946 kVA	2004 - 0001, Attachment B, page 1 Maximum, {5.2.2}

Bus	Breaker	Service	Load	Basis
1A - 01	1A52 - 08	Heater Drain Pump 1P - 027A	339 kVA	2004 - 0001, Attachment B, page 1 Maximum, {5.2.2}
1A - 01	1A52 - 09	Heater Drain Pump 1P - 027C	344 kVA	2004 - 0001, Attachment B, page 1 Maximum, {5.2.2}
1A - 05	1A52 - 58	Station Service Transformer 1X - 13	1349 kVA	2004 - 0001, Attachment B, page 2 Maximum, {5.2.2}
1A - 02	1A52 - 10	Heater Drain Pump 1P - 027B	341 kVA	2004 - 0001, Attachment B, page 1 Maximum, {5.2.2}
1A - 02	1A52 - 11	Condensate Pump 1P - 025B	940 kVA	2004 - 0001, Attachment B, page 1 Maximum, {5.2.2}
1A - 02	1A52 - 12	Circulating Water Pump 1P - 030B	1862 kVA	2004 - 0001, Attachment B, page 1 Maximum, {5.2.2}
1A - 02	1A52 - 13	Steam Generator Feedwater Pump 1P - 028B	4196 kVA	2004 - 0001, Attachment B, page 1 Maximum, {5.2.2}
1A - 02	1A52 - 14	Reactor Coolant Pump 1P - 001B	4431 kVA	2004 - 0001, Attachment B, page 1 Maximum, {5.2.2}
1A - 02	1A52 - 15	Station Service Transformer 1X - 12	643 kVA	2004 - 0001, Attachment B, page 1 Maximum, {5.2.2}

Bus	Breaker	Service	Load	Basis
1A - 06	1A52 - 84	Station Service Transformer 1X - 14	1070 kVA	2004 - 0001, Attachment B, page 2 Maximum, {5.2.2}
1A - 06	1A52 - 81	Station Service Transformer 1X - 06	129 kVA	2004 - 0001, Attachment B, page 2 Maximum, {5.2.2}
1A - 04	1A52 - 53	Transformer X - 704	300 kVA	Transformer Rating {5.2.2}
		Transformer X - 45	75 kVA	Transformer Rating {5.2.2} {5.2.1, p416}
H - 02	H52 - 23	Transformers X - 65, X - 66 & X - 72	785 kVA	2004 - 0001, Attachment B, page 3 Maximum Peak, {5.2.2}
H - 02	H29 - 24	Transformer XL - 45	50 kVA	Transformer Rating {5.2.1, page 138}
2A - 01	2A52 - 19	Heater Drain Pump 2P - 027C	347 kVA	2004 - 0001, Attachment B, page 1 Maximum, {5.2.2}
2A - 01	2A52 - 20	Heater Drain Pump 2P - 027A	346 kVA	2004 - 0001, Attachment B, page 1 Maximum, {5.2.2}
2A - 01	2A52 - 21	Condensate Pump 2P - 025A	964 kVA	2004 - 0001, Attachment B, page 1 Maximum, {5.2.2}
2A - 01	2A52 - 22	Circulating Water Pump 2P - 030A	1927 kVA	2004 - 0001, Attachment B, page 1 Maximum, {5.2.2}

Bus	Breaker	Service	Load	Basis
2A - 01	2A52 - 23	Steam Generator Feedwater Pump 2P - 028A	4105 kVA	2004 - 0001, Attachment B, page 1 Maximum, {5.2.2}
2A - 01	2A52 - 24	Reactor Coolant Pump 2P - 001A	4394 kVA	2004 - 0001, Attachment B, page 1 Maximum, {5.2.2}
2A - 01	2A52 - 25	Station Service Transformer 2X - 11	788 kVA	2004 - 0001, Attachment B, page 1 Maximum, {5.2.2}
2A - 05	2A52 - 75	Station Service Transformer 2X - 13	1055 kVA	2004 - 0001, Attachment B, page 2 Maximum, {5.2.2}
2A - 02	2A52 - 28	Station Service Transformer 2X - 12	920 kVA	2004 - 0001, Attachment B, page 2 Maximum, {5.2.2}
2A - 02	2A52 - 29	Reactor Coolant Pump 2P - 001B	4332 kVA	2004 - 0001, Attachment B, page 2 Maximum, {5.2.2}
2A - 02	2A52 - 30	Steam Generator Feedwater Pump 2P - 028B	4223 kVA	2004 - 0001, Attachment B, page 2 Maximum, {5.2.2}
2A - 02	2A52 - 31	Circulating Water Pump 2P - 030B	1864 kVA	2004 - 0001, Attachment B, page 2 Maximum, {5.2.2}

Bus	Breaker	Service	Load	Basis
2A - 02	2A52 - 32	Condensate Pump 2P - 025B	942 kVA	2004 - 0001, Attachment B, page 2 Maximum, {5.2.2}
2A - 02	2A52 - 33	Heater Drain Pump 2P - 027B	381 kVA	2004 - 0001, Attachment B, page 2 Maximum, {5.2.2}
2A - 06	2A52 - 89	Station Service Transformer 2X - 14	1476 kVA	2004 - 0001, Attachment B, page 2 Maximum, {5.2.2}
2A - 06	2A52 - 92	Station Service Transformer 2X - 06	129 kVA	2004 - 0001, Attachment B, page 2 Maximum (by a review of the ETAP database, the MCC 2B - 40 load is considered to be the same size as the MCC 1B - 40 load), {5.2.2}
2A - 04	2A52 - 50	Transformer X - 07	294 kVA	2004 - 0001, Attachment D, page 61 Connected {5.2.2}
H - 03	H29 - 34	Transformer XL - 46	50 kVA	Transformer Rating {5.2.1, page 156}

The total load is increased by 2.5 % to account for the real and reactive power losses. The result is then rounded up to 62 MVA. (This rounding incidentally results in an additional margin of about 900 kVA.) See Section 47 of Attachment B.

It is important to recognize that this loading level has been established for the purpose of evaluating the relay tap setting, and does not consider the impact of the loading level on the auxiliary system performance, as that analysis is beyond the scope of this calculation.

4.2.15 It is assumed that the heater drain pump motors will accelerate to rated speed fast enough so as to not result in a trip of the COM - 5 overcurrent relay during motor starting with its present setting of tap 5, time dial 1.

Basis: No false trips of these relays have occurred throughout the historical plant operation.

5.7 Computer Programs

5.7.1 Electrical Transient Analyzer Program (ETAP) - Version 5.0.3N (S&L Program No. 03.7.696 - 5.03).

5.7.2 Mathcad Program - Version 11.2a.

6. *Calculations*

The following text sections addressed in Section 7 of the Base Calculation are impacted by this calculation minor revision:

6.1. New Section 7.1.36 for MDAFW Pump 2P-53 which will read as follows:

MDAFW Pump 2P-53 Motor - Page A57, and Section 52 of Attachment B.

The MDAFW 2P-53 motor COM - 5 relay time overcurrent (TOC) pickup and ITH and IIT instantaneous settings are developed in Attachment B, Section 52. The coordination with the upstream relays/breakers is analyzed on Pages A41 and A47.

6.2. New Section 7.1.37 for MDAFW Pump 1P-53 which will read as follows:

MDAFW Pump 1P-53 Motor - Page A58, and Section 53 of Attachment B.

The MDAFW 1P-53 motor 51Y (time overcurrent), 50D (instantaneous), and 49 (overload) settings are developed in Attachment B, Section 53. The coordination with the upstream relays is bounded by Pages A40 and A46.

6.3. Section III.8.06 of Calculation 2004-0002 (Reference 8.2.2) imposes the following limitation:

"This calculation imposes a limitation on the AFW modifications that the protective devices for the new AFW pump motors must be set to trip at a current of at least 50A. In addition, the protective device tripping time at 204A must exceed 7 seconds, and the tripping time at 62A must exceed 50 seconds."

As can be seen from the ETAP plots in Attachment A, Pages A57 and A58, the requirements of the imposed limitation have been met. Additionally, the alarm relay pickup of 50A matches the minimum pickup setting of the imposed limitation. Also, for Pump 2P-53 the 62A @ 50 seconds point from the imposed limitation falls within the alarm region but below the HDO setting of the relay.

6.4 Motor Starting Current margin

Section 2.1.3.6 of the base calculation (Ref. 8.1.2) states that a 2 second margin should be maintained between the motor time current curve at minimum rated voltage and the motor overcurrent relay curve. At 76.9%V and a starting time of 3 seconds, it can be seen on plots A57 and A58 that a margin of at least 2 seconds is obtained.

6.5 Feeder Protection

Page B116 of the base calculation determines that the feeder current does not exceed 897A during starting of the largest motor with the bus loaded at minimum voltage. Since the feeder breakers are set at 3000A, the addition of the MDAFW motors at (43A/0.85) = 50.6A will not trip the breaker.

8.2 Coordination and Protection Conclusions

8.2.1 Reactor Coolant Pump Motor

The existing tap, high drop out instantaneous, and normal instantaneous settings of the COM – 5 relay are acceptable. See Section 2 of Attachment B.

The 51L relay time dial setting may result in a trip of the motor during a start at 80 % voltage, since the calculated accumulated travel of 96 % is greater than the limit of 90 % maximum travel. See Section 3 of Attachment B.

The COM – 5 relay time dial setting will not result in a trip of the motor at either 80 % or 100 % starting voltage.

The time dial of the 51L relay can not be adjusted upwards without compromising the locked rotor protection for 80 % voltage. See the coordination curve plotted on Attachment page A1.

Additional relaying, such as an impedance relay, should be considered for this motor if the capability to start the motor at 80% voltage while maintaining protection is desired.

Coordination is maintained for motor starts at both 80 % and 100 % voltage between the reactor coolant pump motor relays and the upstream bus feed relays for Buses 1A - 01, 1A - 02, 1A - 03, 1A - 04, 2A - 01, 2A - 02, 2A - 03 and 2A - 04. See Sections 4 and 5 of Attachment B.

8.2.2 Steam Generator Feedwater Pump Motor

The existing tap, high drop out instantaneous and normal instantaneous settings of the COM – 5 relay are acceptable. See Section 6 of Attachment B.

The steam generator feedwater pump motor is protected by the existing COM - 5 settings, but will trip during a motor start at 80 % voltage (146 % travel), based on the available data. There is a slight chance the motor may trip during a motor start at 100 % voltage (91 % travel). See page A2 and Section 7 of Attachment B.

Consideration should be given to adding another overcurrent relay with a more inverse slope, and resetting the existing COM - 5 relay if the capability to start the motor at less than 100% voltage while maintaining protection is desired. Alternatively an impedance relay could be added to protect this motor.

8.2.3 Condensate Pump Motor

The recommended time dial changes for the Condensate Pump protective relays associated with A/R 01037571 (see Section 8.5) are partially implemented (for Unit 2 motors only) at this time (issue of Revision 2 of this calculation). References 5.6.36 and 5.6.47 have been updated to reflect the new settings. Both the new revision of these documents and the revision used in the initial evaluation performed in Revision 2 of this calculation are listed in Section 5.6 for completeness. For continuity at the time of issuing Revision 2 of this calculation, the original settings for these relays are shown in Section 6 to capture the full evaluation process supporting the recommended setting changes.

The existing tap, high dropout instantaneous and normal instantaneous settings of the COM – 5 relay are acceptable. See Section 8 of Attachment B.

The condensate pump motor may trip with the type COM - 5 relay existing time dial setting at 100 % voltage (104 % travel), based on the available data. The setting should be increased to time dial 3.5. Note that a time dial of 3.5 does not ensure successful starting at 80 % voltage (93 % travel), but increasing the time dial further sacrifices thermal protection for the motor.

See pages A3 and A4, Section 9 of Attachment B, and pages C1, C2, C8 and C9.
If the capability to start the motor at 80% voltage while maintaining protection is desired, consideration should be given to adding another overcurrent relay with a more inverse slope, and resetting the existing COM - 5 relay. Alternatively an impedance relay could be added to protect this motor.

If it can be demonstrated that the motor will never start at 80 % voltage because of its small size (1250 hp), then the recommended relay setting can be considered adequate.

8.2.4 Circulating Water Pump Motor

The existing tap, high dropout instantaneous and normal instantaneous settings of the COM – 5 relay are acceptable. See Section 10 of Attachment B.

From the coordination curve shown on Attachment page A5, and the relay travel calculations contained in Section 11 of Attachment B, the circulating water pump motor is properly protected, and the relay setting will allow the motor to start without tripping.

8.2.5 Heater Drain Pump Motor

The existing tap, high drop out instantaneous and normal instantaneous settings of the COM – 5 relay are acceptable. See Section 12 of Attachment B.

From the coordination curve shown on Attachment page A6, the heater drain pump motor is properly protected.

No motor starting time data is available to support meaningful relay travel calculations for these motors. There has been no history of nuisance tripping on overcurrent while starting these pumps, so the existing time dial setting is considered adequate to support motor starting {4.2.15}.

8.2.6 Safety Injection Pumps 1P-015A and 2P-015A

The existing tap and high drop out instantaneous settings of the COM - 5 relay are acceptable. The existing normal instantaneous setting of 30 (900 amperes) of the COM - 5 relay is less than the recommended value of 200 % of LRC. The recommended normal instantaneous setting of 35 (1050 amperes) is close to the recommended value of 200 % of LRC. See Section 13 of Attachment B.

The coordination plots on pages A7 and A8 show that the 1P-015A and 2P-015A motors are not thermally protected for starting and accelerating at all voltage levels for hot or cold starts with the existing time dial setting of 3.

The coordination plot on page A7A shows that with the recommended time dial setting of 2.2, motor 1P - 015A is adequately protected for hot or cold starts at 85% of motor rated voltage, but not protected for either hot or cold starts at 100% of motor rated voltage.

The coordination plot on page A9 shows that with the recommended time dial setting of 2.2, motor 2P - 015A is adequately protected for cold starts but may not be completely protected for hot starts at 85% of motor rated voltage, and is not protected for either hot or cold starts at 100% of motor rated voltage.

The relay travel calculations in Sections 14 and 15 of Attachment B show that the motors will successfully start with the existing time dial setting of 3, and also with the recommended time dial setting of 2.2 (89 % travel for 1P - 015A and 80 % travel for 2P - 015A at 85 % starting voltage).

Coordination between the COM - 5 time overcurrent relay of the Train A safety injection pump motors and the upstream bus normal feed and diesel generator relays is maintained, and meets the acceptance criteria in Sections 3.2.1, 3.2.6 and 3.2.7. See the coordination plots on pages A38, A39, A42 and A43 and the analysis in Section 41 of Attachment B.

NOTE: When the recommended INST setpoint of 35 is implemented, the recommended time dial setting of 2.2 must be implemented at the same time (or earlier) to maintain coordination with the diesel generators G-01 and G-02 panel and switchgear breaker CO-5 relays. See Section 41 of Attachment B and coordination plots A42 & A43.

8.2.7 <u>Safety Injection Pumps 1P-015B and 2P-015B</u>

The existing ABB 49 alarm relay setting and 51L relay tap and time dial settings are acceptable. The existing 50D relay instantaneous setting of 30 (900 amperes) is less than the recommended value of 200 % of LRC. The recommended 50D relay instantaneous setting of 35 (1050 amperes) is close to the recommended value of 200 % of LRC. See Section 16 of Attachment B.

The coordination plot on pages A10 and A10A show that the 1P-015B and 2P-015B motors are thermally protected for starting and accelerating at all voltage levels for both hot and cold starts.

The 51L relay travel calculations in Section 17 of Attachment B show that the motor can successfully start at the minimum voltage (73 % travel).

The 49 relay time delay has been set to its minimum value. The alarm will be activated well before the safety injection pump motor running overload thermal limit curve is reached. Note, however, that the setting will provide little or no time for the operators to react to reduce the load on the motor for overloads greater than the pickup of the 51L relay (140 % of the motor full load current) before the 51L relay trips.

Coordination between the 51L relay of the Train B safety injection pump motors and the upstream bus normal feed and diesel generator relays is maintained, and meets the acceptance criteria in Section 3.2.1 and 3.2.6. See the coordination plots on pages A40, A41, A46 and A47 and the analysis in Sections 18 and 43 of Attachment B.

Coordination is not maintained between the 50D relay of the Train B safety injection pump motors and the 51E relays at breakers 1A52 - 77 and 2A52 - 96 with the 51E relay existing setting of tap 10, time dial 5.1. The coordinating time interval is only 0.19 second, versus a required time of 0.25 second when the upstream relay is static. See Section 2.1.2 and the coordination plot on page A40.

Coordination between the 50D relay of the Train B safety injection pump motors and the 51E relays at breakers 1A52 - 77 and 2A52 - 96 is maintained with the 51E relay recommended setting of tap 10, time dial 7.5. The coordinating time increases to 0.31 second. See the coordination plot on page A41 and the analysis in Section 40 of Attachment B.

8.2.8 Station Service Transformers 1X - 11, 1X - 12, 2X - 11 and 2X - 12

The existing setting of the type CO - 8 relay for station service transformers 1X - 11, 1X - 12, 2X - 11 and 2X - 12 does not provide short circuit protection for the transformer. The time dial setting should be decreased to time dial 3. See the coordination curves on Attachment pages A11 and A12.

With the recommended time dial setting, there will be some loss of coordination with the downstream main 480 V breaker for a 4160 V fault current between about 560 A and 1020 A. Note that the same load is tripped by the high side relay and the low side main breaker.

With the recommended time dial setting, there is also a loss of coordination with the bus tie breaker to the safety - related 480 V bus. (When the tie breaker is used to feed the safety - related bus from the non - safety - related bus, the train is declared inoperable {5.11.21, 5.11.22}.)

Coordination is maintained between the CO - 8 relay and the 480 V load breakers, and also between the low side main breaker and the 480 V load breakers, and therefore the coordination meets the acceptance criterion explained in Section 3.2.1.

Coordination is not maintained between the low side main breaker and the bus tie breaker to safety - related bus 1B - 03.

The instantaneous setting is too low, and should therefore be increased to 160 A, corresponding to a level of about 200 % of the through fault current. See Section 19 of Attachment B.

The recommended new settings are provided on pages C1, C2, C8 and C9.

Simultaneous perfect coordination and protection would require a new relay which has two definite time settings, and a variable slope, similar to the General Electrical Multilin type 745, in order to match the shape of the main low voltage breaker. The high setting would equal the recommended instantaneous setting. The low definite time setting would be set above the short time pickup of the main low voltage breaker, with a time delay of about 1 second. The time overcurrent unit of the relay would be set to match the long time delay unit of the 480 V main breaker, while providing overload protection for the transformer.

8.2.9 Station Service Transformers 1X - 13 and 2X - 13

The existing setting of the type CO - 8 relay for station service transformers 1X - 13 and 2X - 13 provides, at best, only marginal short circuit protection for the transformer. The time dial setting should be decreased to time dial 2. See the coordination curves on Attachment pages A13 and A14.

This setting will result in some loss of coordination with the downstream main and tie 480 V breakers for a 4160 V fault current between about 1100 A and 1530 A. Note that the same load is tripped by the high side relay and the low side breakers.

Coordination is maintained between the CO - 8 relay and the 480 V load breakers, and also between the low side main and tie breakers and the 480 V load breakers, and therefore the coordination meets the acceptance criterion explained in Section 3.2.1.

There is an unavoidable loss of coordination with the generator G - 01 and G - 02 panel and switchgear overcurrent relays. See Section 8.2.24.

The instantaneous setting is too low, and should therefore be increased to 99 A, corresponding to a level of about 200 % of the through fault current. See Section 20 of Attachment B.

The recommended new settings are provided on pages C5 and C12.

Simultaneous perfect coordination and protection would require a new relay which has two definite time settings, and a variable slope, similar to the General Electrical Multilin type 745, in order to match the shape of the main low voltage breaker. The high setting would equal the recommended instantaneous setting. The low definite time setting would be set above the short time pickup of the main low voltage breaker, with a time delay of about 1 second. The time overcurrent unit of the relay would be set to match the long time delay unit of the 480 V main breaker, while providing overload protection for the transformer.

8.2.10 Station Service Transformers 1X - 14 and 2X - 14

The existing setting of the type 51E relay for the station service transformers 1X - 14 and 2X - 14 provides, at best, only marginal short circuit protection for the transformer. The time dial setting should be decreased to time dial 4.5 for improved protection, while the time overcurrent pickup should be increased to tap 10 to maintain coordination. See the coordination curves on Attachment pages A15 and A16.

The 50D relay time delay of 0.1 second will allow the offset of a through fault current to decay before a trip signal is initiated. See Section 20 of Attachment B.

The recommended new settings for the 51E relay are provided on pages C7 and C14.

8.2.11 Station Service Transformers 1X - 06 and 2X - 06

The existing setting of the 51E relay for station service transformers 1X - 06 and 2X - 06 is acceptable. See the coordination curve on page A17.

The existing setting of the 50D relay is a low percentage of the through fault current, even though the maximum relay range value is used. The setting is considered to be acceptable since there are no time delay breakers on the secondary of the transformer, and a 6 cycle (0.1 second) time delay is used for the 50D relay, which provides coordination with the maximum tripping time of less than 0.02 second for the MCC breakers for fault currents at this level.

See Section 21 of Attachment B.

8.2.12 South Gatehouse Switch Fuse Unit (Transformers X - 704 and X - 45)

The existing setting of the type CO - 9 relay for the south gatehouse switch fuse unit protects 300 kVA transformer X - 704, but does not coordinate with the downstream fuse or the largest 480 V breaker. It is impractical to achieve coordination in this case. Coordination with the 480 V breakers is not required since this transformer does not feed a load center.

The relay setting should be adjusted slightly for better overload protection and an optimum instantaneous pickup.

The 200 A fuse rating is large enough to carry the combined load of the two transformers, but is too high to provide proper overload protection for either transformer X - 704 (480 % of full load current) or transformer X - 45 (1921 % of full load current).

Protection for the 75 kVA transformer X - 45 should be provided by a separate fuse.

The replacement of the 200 A fuse with a smaller fuse is not necessary since the upstream relay provides the required protection for the 300 kVA transformer.

See Attachment pages A18 and A19, Section 22 of Attachment B, and page C4.

8.2.13 Warehouse Transformer X - 07

The existing setting of the type CO - 9 relay for 500 kVA warehouse transformer X - 07 protects the transformer, but does not coordinate with the downstream fuse and power panel main breaker. It is impractical to achieve complete coordination in this case. Coordination with the 480 V breakers is not required since this transformer does not feed a load center.

The relay time overcurrent pickup should be increased for improved coordination with the low voltage breakers.

The relay existing instantaneous setting is too high, and should be lowered.
The 200 A fuse is properly sized.

See Attachment pages A20 and A21, Section 23 of Attachment B, and page C11.

8.2.14 Alternate Shutdown Transformer X - 08

The existing time dial setting of the type CO - 9 relay for 2500 kVA alternate shutdown transformer X - 08 does not protect the transformer.

Also, the existing instantaneous setting is too low.

The CO - 9 setting should be changed to tap 10, time dial 3.5, instantaneous 92 A.

See pages Attachment pages A22 and A23, Section 24 of Attachment B, and page C16.

8.2.15 Switchyard Auxiliary Transformer X - 48

The existing time dial setting of the type CO - 9 relay for switchyard auxiliary transformer X - 48 provides no protection for the transformer.

Also, the instantaneous setting is too low.

The setting should be changed to time dial 5, instantaneous 49 A, with the pickup remaining at 3 A.

Coordination with the 480 V breakers is not required since this transformer does not feed a load center.

See Attachment pages A24 and A25, Section 25 of Attachment B, and page C16.

8.2.16 North Service Building Transformer X - 27

The existing time dial setting of the type CO - 9 relay for 1500 kVA north service building transformer X - 27 does not protect the transformer.

Also, the instantaneous setting is too low.

The CO - 9 setting should be changed to tap 12, time dial 1.5, instantaneous 112 A.

This setting results in a minor loss of coordination with the main low side breaker B52 – 49A and high side fuse for a 13.8 kV level fault current between about 240 A and 320 A. Note that loss of coordination between devices in a single series path is considered to be acceptable as long as the same load is lost {3.2.1}.

The main low voltage breaker will not coordinate with the 480 V load breakers due to the instantaneous unit of the main breaker. This breaker must be replaced with a new breaker having only long time and short time delay elements in order to coordinate with the 480 V load breakers.

The fuse size of 100 A is sufficiently large to carry the continuous current of this self cooled transformer (159 % of the full load current), although it is smaller than the size recommended by the National Electrical Code. From an examination of the fuse characteristic curve as drawn on the coordination plot, the fuse apparently may melt during the transformer inrush. If no fuse operations have been experienced this potential problem may not be a genuine concern.

See Attachment pages A26 and A27, Section 26 of Attachment B, and page C16.

8.2.17 Transformers X - 65, X - 66 and X - 72

The setting of the type CO - 9 relay for the feed to transformers X - 65, X - 66 and X - 72 coordinates with the downstream transformer high side fuses.

Reduce the relay time dial slightly to maintain coordination with the revised setting of the generator G - 05 COV - 8 relay.

The main low voltage breaker of transformer X - 72 will not coordinate with the 480 V load breakers for a fault close to the 480 V bus due to the instantaneous unit of the main breaker.

The transformers X - 65, X - 66 and X - 72 feed MCC's, rather than load centers. Therefore the acceptance criterion included in Section 3.2.1 requiring coordination for load centers does not apply to these transformers.

The S&C type SM - 5, 50E fuses for the 500 kVA transformers X - 65 and X - 72 are properly sized. The 65E fuse for the 750 kVA transformer X - 66 is slightly smaller than the recommended size, but is adequate to carry the transformer rated load.

The transformer X72 fuse does not coordinate with the main low voltage breaker. (Note that, as explained in Section 3.2.1, full coordination between two protective devices in a single series path is not required, as long as the same load is tripped.)

See Attachment pages A28 and A29, Section 27 of Attachment B, and page C17.

8.2.18 Transformer X - 500

This 225 kVA transformer is protected only by a Westinghouse type CLE, 15E high side fuse.

The fuse size of 15 A is sufficiently large to carry the continuous current of this self cooled transformer (159 % of the full load current), although it is smaller than the size recommended by the National Electrical Code. From an examination of the fuse characteristic curve as drawn on the coordination plot, the fuse apparently may melt during the transformer inrush. If no fuse operations have been experienced this potential problem may not be a genuine concern.

The high side fuse does not coordinate with the generator G - 05 COV - 8 relay above the existing instantaneous pickup of the relay. For the recommended relay setting, the fuse and relay fully coordinate.

The high side fuse does not coordinate with the main low voltage breaker, but since the same load is tripped, this loss of coordination is considered acceptable.

The high side fuse does not coordinate with the largest load breaker, which is the feeder to MCC B - 500.

The main low voltage breaker will not coordinate with the 480 V load breakers at the maximum fault level due to the instantaneous unit of the main breaker.

See Attachment pages A30 and A31, and Section 28 of Attachment B.

8.2.19 Transformers XL - 45 and XL - 46

The transformers XL - 45 and XL - 46 are single phase 50 kVA transformers which are protected by Gould Amp Trap type CS - 3, 15E fuses.

The 15 A fuse size is greater than the maximum size recommended by the National Electrical Code (414 % of transformer full load current versus 300 %). A 10 A fuse size (276 % of transformer full load current) should be considered.

The fuse with either the existing or recommended size will not blow on transformer inrush.

See Attachment pages A32 and A33, and Section 29 of Attachment B.

8.2.20 Normal feed to Buses 1A - 01, 1A - 02, 2A - 01 and 2A - 02 from the UAT

For the UAT feed to Buses 1A - 01, 1A - 02, 2A - 01 and 2A - 02, the existing setting for the bus normal feed CO - 8 relay coordinates with the downstream motor and transformer relays, but does not protect the UAT at the maximum fault level. The upstream bus feeder cable is protected for downstream faults by the CO - 8 relay, since the capability of the feed in this situation is based on all 6 of the conductors in this feed carrying the short circuit current. See Section 2.1.5.2.

The bus normal feed relay (UAT low side CO - 8 relay) does not coordinate with the UAT high side CO - 6 relay, since the two curves are touching at one point. The CO - 6 relay does not provide protection for the UAT or the bus feeder cable (since the cable capability in this case is based on the short circuit current flowing through only one conductor - see Section 2.1.5.2). Short circuit protection for a fault within the differential zone is provided for the UAT and bus feeder cable by the transformer differential relay {5.3.5, 5.3.9}.

It is recommended that the CO - 8 time dial be reduced to 8 in order to provide proper short circuit protection for the transformer and the cable feed for a downstream fault, and to coordinate with the high side relay. This time dial change for the bus normal feed relay is important since the high side overcurrent relay does not completely protect the transformer.

The pickup of the CO - 8 relay (referred to the CT primary) is 169 % of the bus full load current.

During reactor coolant pump motor starting with a fully loaded bus, the margin in tripping time between the CO - 8 relay with its recommended time dial setting and the 51L relay for the reactor coolant pump motor is 15.9 seconds at 100 % voltage, and 18.8 seconds at 80 % voltage. Therefore coordination is maintained under these conditions. With the existing setting of the CO - 8 relay, the coordination margin will be greater, since the new setting is faster than the existing setting, and therefore bounds the existing setting.

See the coordination curves on Attachment pages A34 and A35, Sections 4 and 37 of Attachment B, and the recommended relay setting on pages C1, C2, C8 and C9.

8.2.21 <u>Alternate feed to Buses 1A - 01, 1A - 02, 2A - 01 and 2A - 02 from the LVSAT Through Buses 1A - 03, 1A - 04, 2A - 03 and 2A - 04</u>

For the LVSAT feed to Buses 1A - 01, 1A - 02, 2A - 01 and 2A - 02, the Bus 1A - 03, 1A - 04, 2A - 03 or 2A - 04 normal feed CO - 8 relay with its existing setting of tap 8, time dial 2.9, coordinates with the downstream motor and transformer relays, and protects the LVSAT.

The LVSAT high side CO - 9 relay with its existing setting of tap 8, time dial 2.7, also protects the transformer, but does not coordinate with the downstream normal feed CO - 8 relay.

The CO - 8 bus feed relay should be adjusted downward slightly to time dial 2.8, while the LVSAT high side CO - 9 relay setting should be changed to tap 7, time dial 3.6, in order to maintain coordination between these two relays.

The tap of the CO - 9 relay is reduced from 8 to 7 in order to facilitate coordination with the relays upstream of the LVSAT on the secondary and primary sides of the HVSAT.

The pickup of the CO - 8 relay (referred to the CT primary) is 181 % of the bus full load current.

During reactor coolant pump motor starting with a fully loaded bus, the margin in tripping time between the CO - 8 relay with its recommended time dial setting and the 51L relay for the reactor coolant pump motor is 4.1 seconds at 100 % voltage, and 1.1 seconds at 80 % voltage. Therefore coordination is maintained under these conditions. With the existing setting of the CO - 8 relay, the coordination margin will be greater, since the new setting is faster than the existing setting, and therefore bounds the existing setting.

See the coordination curves on Attachment pages A36, A37, A51 and A52.

Also see the calculations in Sections 5, 38 and 47 of Attachment B, and the recommended settings on pages C3, C4, C10, C11, C17 and C18.

8.2.22 Buses 1A - 05 and 2A - 05 fed from the LVSAT Through Buses 1A - 03 and 2A - 03

There is no overcurrent relaying at the main breaker for Bus 1A - 05 or 2A - 05, so the full load current of these buses when fed from the offsite source is not an issue.

For the feed from Bus 1A - 03 to Bus 1A - 05, or from Bus 2A - 03 to Bus 2A - 05, coordination is maintained between the motor and transformer feeder overcurrent relays and the upstream bus normal feed CO – 8 relay.

The coordination between the upstream CO - 8 relay and the safety injection pump motor COM - 5 relay during motor starting with a fully loaded bus is enveloped by the starting of the reactor coolant pump motor, since the reactor coolant pump motor is so much larger. Therefore no coordination calculation has been performed for the Train A safety injection pump motor starts.

The cables to Buses 1A - 05 and 2A - 05 are not protected by the upstream bus normal feed overcurrent relay. This loss of protection is acceptable, since the bus differential zone for Buses 1A - 03 and 2A - 03 includes the cable {5.3.2, 5.3.3, 5.3.6 and 5.3.7}.

See the coordination curves on Attachment pages A36 through A39, Sections 5, 38 and 39 of Attachment B, and pages C3 and C10.

8.2.23 Buses 1A - 06 and 2A - 06 fed from the LVSAT Through Buses 1A - 04 and 2A - 04

The existing time dial setting of 5.1 for the 51E relay at the normal feed breakers for Buses 1A - 06 and 2A - 06 results in a loss of coordination with the downstream motor and transformer feeder 50D relays.

The recommended time dial setting of 7.5 for the 51E relay at the normal feed breakers for Buses 1A - 06 and 2A - 06 maintains coordination with the downstream motor and transformer feeder 50D relays.

The normal feed 51E relays at Buses 1A - 06 and 2A - 06 with either the existing or recommended settings do not coordinate with the feeder CO - 8 relays at Buses 1A - 04 and 2A - 04, but there is no need to coordinate these relays since the same load is tripped.

The CO - 8 relay for the feeder from Bus 1A - 04 to Bus 1A - 06 has marginally acceptable coordination with the downstream transformer 50D relays. The coordination time of 0.31 second meets the requirement for the coordination between a calibrated upstream electromechanical relay and a downstream static relay. The coordination margin has been reduced from 0.17 second to 0.13 second. See Section 2.1.2. No setpoint change is required for the CO - 8 relay and the downstream 50D relays.

Coordination with the upstream CO - 8 relays for the normal feed to Buses 1A - 04 and 2A - 04 is maintained with both the existing and new relay settings.

The pickups of the feeder CO - 8 relay at Bus 1A - 04 and the 51E relay for the main feed to Bus 1A - 06 referred to the CT primary are both 650 % of the Bus 1A - 06 full load current.

During safety injection pump motor starting with a fully loaded bus, the total load is less than the pickup of the 51E relay at Bus 1A - 06 and the CO - 8 relay at Bus 1A - 04. Therefore coordination is maintained under this condition.

See the coordination curves on Attachment pages A17, A40 and A41, Sections 18 and 40 of Attachment B, and pages C4, C6, C11 and C13.

8.2.24 Bus 1A - 05 and 2A - 05 fed from the Diesel Generators G - 01 and G - 02

The maximum full load current of Bus 1A - 05 or 2A - 05 is 364 A (as determined in Section 41 of Attachment B from the full load current values listed in Sections 6.5 and 6.11 of this calculation). The full load current of the generators G - 01 and G - 02, corresponding to the 2000 - hour rating of 2850 kW, is 495 A {5.5.3}. The diesel generator panel type CO - 5 relay will pickup at 600 A. The diesel generator switchgear breaker type CO - 5 relay will pickup at 560 A. Therefore the panel and switchgear breaker relay pickups are greater than both the bus full load current and the diesel generator rated current. See Section 41 of Attachment B.

The evaluation of the emergency diesel generator overcurrent relay pickup values relative to the loading of the generators considers the plant operating procedures, which dictate that plant personnel must manually limit the loading of the generators. For generators G - 01 and G - 02 the load must be limited to the 2000 - hour rating of the generator {5.11.19, 5.11.20}.

The initial short circuit current from the G - 01 and G - 02 generators is 1.6 kA. See Section 33 of Attachment B.

The diesel generator panel and breaker relays will not trip after a short circuit with no field forcing. The steady state short circuit current of 265 A under this condition will result in the eventual tripping of the safety injection pump motor COM - 5 relays and the 480 V load breakers, but will not result in tripping of the transformer 1X - 13 and 2X - 13 CO - 8 relays. See Section 41 of Attachment B.

With a field forcing current of 736 A, the panel relays (51A, B, C / G01 (G02)) will take about 20 seconds to trip. The switchgear breaker relays (51/50 A,B,C/A52-60, 51/50 A,B,C/A52-66, 51/50 A,B,C/A52-73, 51/50 A,B,C/A52-67) will take about 17 seconds to trip.

The A/R # 01068879 recommends evaluating, and if possible resolving, the limitation of the present system design whereby it is not possible to trip the generator after a short circuit when the field forcing has failed. Potential remedial measures for this condition include the use of voltage controlled or restrained relays, or impedance relays. These relays would also reduce the tripping time when the field forcing is in service.

The coordination when Bus 1A - 05 is fed from generator G - 01 is shown on Attachment pages A42 and A43.

The station service transformer type CO - 8 relays do not coordinate with the diesel generator panel and breaker relays. The CO - 8 relays will not trip when the transformer is fed from the generator, since the pickup is 800 A, while the field forcing current is only 736 A. This loss of coordination is inherent in this application due to the large size of the station service transformer relative to the size of the generator.

There is also a loss of coordination with the 480 V main and bus tie breakers.

Coordination with the 480 V load breakers is maintained. The field forcing current of 736 A @ 4.16 kV = 6379 A @ 480 V will be above the instantaneous or short time pickup of the 480 V load breakers.

Coordination between the diesel generator panel relays (51A,B,C/G01, 51A,B,C/G02) and switchgear breaker relays (51/50 A,B,C/A52-60, 51/50 A,B,C/A52-66, 51/50 A,B,C/A52-73, 51/50 A,B,C/A52-67), and the safety injection pump motor relays is maintained.

The diesel generator is thermally protected, since the panel and breaker CO – 5 relay characteristic curves lie below the curve reflecting a constant I^2t corresponding to 3 times generator current for 10 seconds.

No setting change is recommended to achieve coordination with the station service transformer relay, since this change would reduce the protection of the generator.

The instantaneous unit of the switchgear CO – 5 relay should be used and set at about twice the diesel generator initial fault current. The instantaneous unit will detect a fault inside the generator during diesel generator testing while synchronized to the offsite power system. This protection is strongly recommended since diesel generators G - 01 and G - 02 are not provided with differential protection {5.3.15, 5.3.16}.

The coordination between the Bus 1A - 03 normal feed CO - 8 relay and the generator G - 01 CO - 5 panel and switchgear relays during diesel generator testing is shown on pages A44 and A45. There is no coordination above a fault current of about 13,000 A when the instantaneous unit of the switchgear breaker relays is not used.

Coordination is maintained between the switchgear breaker relays and the normal feed relay when the instantaneous unit is set. Mis-coordination of the CO - 8 normal feed relay with the panel relays remains, but would only be of significance if a switchgear breaker relay failed to operate. See also Section 42 of Attachment B, and pages C5 and C12.

8.2.25 <u>Bus 1A - 06 and 2A - 06 fed from the Diesel Generators G - 03 and G - 04</u>

The maximum full load current of Bus 1A - 06 or 2A - 06 is 460 A (as determined from the full load current values listed in Sections 6.6 and 6.12 of this calculation). The full load current of the generators G - 03 and G - 04, corresponding to the 2000 - hour rating of 2848 kW, is 494 A {5.8.11}. The generators G - 03 and G - 04 are allowed to operate up to the 200 - hour rating {5.11.19, 5.11.20}. The current corresponding to the 200 - hour rating of 2951 kW is 512 A {5.8.11}. The diesel generator panel type 51E relay will pickup at 1440 A with the existing setting. The diesel generator switchgear breaker type 51E relay will pickup at 1200 A with the existing setting. Therefore the panel and switchgear breaker relay existing pickups are significantly greater than both the bus full load current and the diesel generator 2000 - hour and 200 - hour rated currents. See Section 43 of Attachment B.

The evaluation of the emergency diesel generator overcurrent relay pickup values relative to the loading of the generators considers the plant operating procedures, which dictate that plant personnel must manually limit the loading of the generators. For generators G - 03 and G - 04 the load normally must be limited to the 2000 - hour rating. The load must be limited to the 200 - hour rating during the safety injection mode {5.11.19, 5.11.20}.

The initial short circuit current from the G - 03 and G - 04 generators is 9.4 kA. See Section 34 of Attachment B.

The diesel generator panel and breaker relays will not trip after a short circuit with the existing relay settings and no field forcing. The steady state short circuit current of 1023 A under this condition will result in the eventual tripping of the load breakers. See Section 43 of Attachment B.

With a field forcing current of 1421 A, the panel relay's (51 / G - 03 (G - 04)) existing pickup will be approximately equal to the field forcing current, and therefore the relay will not trip. The switchgear breaker relay will take about 89 seconds to trip with the existing pickup.

The diesel generator is not thermally protected for an I^2t corresponding to 3 times generator current for 10 seconds.

The coordination with the existing relay settings is shown on Attachment page A46. Coordination with the downstream motor and transformer relays is maintained.

The setting of both the panel and breaker relays should be reduced to tap 7 A, time dial 8.5 for improved sensitivity. With the new tap setting the relay pickup is 840 A, which is still greater than both the bus full load current and the diesel generator 2000 - hour and 200 - hour rated currents.

The new tap setting will result in a trip of the diesel generator panel and breaker relays in about 26 seconds at the field forcing current. This new setting does not thermally protect the diesel generator, but does maintain coordination, while resulting in an eventual trip.

Note that although the revised pickup of the panel and breaker relays is only slightly above the recommended pickup of the transformer 1X - 14 (or 2X - 14) 51E relay, loss of coordination at the pickup setting is not a realistic concern, since the transformer can not be overloaded to this level. (The low side main breaker would trip on overloads of this magnitude. See pages A15 and A16.) Only a fault would result in a current level this high. The current will be at least equal to the steady state short circuit current without field forcing (1023 A).

The coordination with the recommended relay setting is shown on Attachment page A47. Coordination with the downstream motor and transformer relays is maintained.

The generators G - 03 and G - 04 are provided with differential protection, so these generators will be immediately tripped off for a fault which occurs during diesel generator testing. Therefore a loss of coordination with the source breaker under this condition is not a concern.

The revised relay settings are shown on pages C6, C7, C13, C14 and C15.

8.2.26 UAT Ground Coordination

Coordination is maintained between the ITH instantaneous ground relays for all of the 4.16 kV feeders on Buses 1A - 01, 1A - 02, 2A - 01 and 2A - 02, and the type CO - 5 neutral time overcurrent relays for UATs 1X - 02 and 2X - 02, windings X and Y.

See Attachment page A48 and Section 44 of Attachment B.

8.2.27 LVSAT Neutral Relay Coordination with the type ITH feeder ground relays

Coordination is maintained between the ITH instantaneous ground relays for all of the 4.16 kV feeders at Buses 1A - 01, 1A - 02, 1A - 04, 1A - 05, 2A - 01, 2A - 02, 2A - 04 and 2A - 05, and the type CO - 9 neutral time overcurrent relays for LVSAT's 1X - 04 and 2X - 04, windings X and Y.

See Attachment page A49 and Section 45 of Attachment B.

8.2.28 LVSAT Neutral Relay Coordination with the type GKT feeder ground relays

Coordination is maintained between the GKT definite time ground relays for all of the 4.16 kV feeders at Buses 1A - 06 and 2A - 06, and the type CO - 9 neutral time overcurrent relay for LVSAT's 1X - 04 and 2X - 04, winding Y.

See Attachment page A50 and Section 46 of Attachment B.

8.2.29 Buses H - 01, H - 02 and H - 03 fed from HVSAT 1X - 03 or 2X - 03

With the existing relay settings, coordination is maintained between the downstream transformer feeder relays and the low side and high side relays for the HVSAT's.

With the existing settings, the low side HVSAT type CO - 9 relays provide short circuit protection for the transformer, but the high side HVSAT type CO - 9 relays do not.

It is recommended that the time dial of both the low side and high side HVSAT relays be reduced to 4.5. This change will enable the high side relay to provide marginally acceptable short circuit protection, while maintaining coordination between the HVSAT relays and the overcurrent relay for the feeder to the LVSAT. The overcurrent relay tap and time dial setting for the feeder to the LVSAT must also be adjusted to maintain coordination with the HVSAT low side relay for the pickup current.

The pickup of the CO - 9 relay on the low side of the HVSAT 1X - 03 (referred to the CT primary) is 158 % of the Bus H01 and H02 combined full load current.

The pickup of the CO - 9 relay on the low side of the HVSAT 2X - 03 (referred to the CT primary) is 164 % of the Bus H01 and H03 combined full load current.

The pickup of the CO - 9 relay on the low side of either HVSAT 1X - 03 or HVSAT 2X - 03 (referred to the CT primary) is 123 % of the Bus H - 01, H - 02 and H - 03 combined assumed maximum loading under the condition when one of the HVSATs is out of service {4.2.14}.

See Attachment pages A51 and A52, Sections 47 and 48 of Attachment B, and pages C17 and C18.

8.2.30 Buses H - 01, H - 02 and H - 03 fed from the Gas Turbine Generator G - 05

Refer to page A53 of this calculation for the coordination with the existing settings of the COV – 8 relay.

The initial short circuit current from the gas turbine generator is about 3.9 kA. The gas turbine type COV - 8 relay instantaneous pickup is set at 3000 A. Coordination is therefore not maintained for a bolted fault when the instantaneous unit of the COV – 8 is used.

The type CO - 9 relay for the feed to the LVSAT is set to pickup at 3200 A. Therefore this relay will never trip when the gas turbine generator is the source, due to the decay in the magnitude of the fault current from the generator. After a short time the fault current magnitude will be significantly less than the pickup value of the CO – 9 relay.

Coordination will be maintained, for a fault through an impedance which limits the magnitude of the fault current to less than 3000 A, between the 13800 V - 480 V transformer feeder type CO - 9 relays, and the gas turbine generator COV - 8 relay, with the instantaneous unit in service.

It is recommended that the instantaneous unit of the COV - 8 relay be set at about twice the gas turbine generator initial fault current in order to maintain coordination with the 13800 V - 480 V transformer feeders at all levels of generator fault current contribution. With this setting for the instantaneous element, the relay will only trip instantaneously when the generator is paralleled with the offsite power system, and a fault occurs within the generator itself.

The COV – 8 relay will not trip with no field forcing when the instantaneous unit is set at about twice the generator initial fault current. See Section 49 of Attachment B.

With field forcing the COV – 8 relay will take at least 20.5 seconds to trip with the maximum estimated field forcing current, and would not trip at all with the minimum estimated field forcing current, when the setting is reduced to tap 2 A, time dial 3.

The A/R # 01068879 recommends evaluating, and if possible resolving, the limitation of the present system design whereby it is not possible to trip the generator after a short circuit when the field forcing has failed. Potential remedial measures for this condition include the use of voltage restrained relays or impedance relays. These relays would also reduce the tripping time when the field forcing is in service.

The gas turbine generator is thermally protected for an I^2t corresponding to 3 times generator current for 10 seconds.

See Attachment page A54 for the coordination with the revised COV – 8 settings.

The revised settings are shown on page C16.

8.2.31 <u>Bus 1A - 05 from G - 05 (Supplied from LVSAT 1X - 04 through Bus 1A - 03)</u>

Coordination is lost between the generator G - 05 type COV - 8 relay with its existing instantaneous setting and the downstream feeder relays on Bus 1A - 05.

Coordination is maintained with the feeder relays for the revised instantaneous unit setting of twice the generator initial fault current.

Coordination is unavoidably lost with the Bus 1A - 03 normal feed relay for both the existing and recommended settings of the COV - 8 relay.

Coordination with the reactor coolant pump motor relays is not required. The generator G - 05 would not be used to recover from an Appendix R fire unless there was also a loss of offsite power. In that case, the reactor coolant pumps would already have tripped on undervoltage {5.3.24 through 5.3.31}.

See Attachment pages A55 and A56, and Section 50 of Attachment B.

8.2.32 <u>Cables and Penetrations</u> {3.2.3}

The curves in Attachment A show that all motor and transformer feeder cables and the reactor coolant pump penetration are provided with short circuit protection, except as noted below.

The cables running to Buses 1A - 01, 1A - 02, 2A - 01 and 2A - 02 from the UATs are not protected by the UAT high side CO - 6 relay at the maximum fault current, but are protected by the UAT differential relay. Therefore the acceptance criterion discussed in Section 3.2.3 is met. See Section 8.2.20.

The cables running from Bus 1A - 03 to Bus 1A - 05, and from Bus 2A - 03 to Bus 2A - 05, are not provided with short circuit protection by the bus overcurrent relay, but the bus differential zone for Buses 1A - 03 and 2A - 03 includes the bus feeder cable. Therefore the acceptance criterion discussed in Section 3.2.3 is met. See Section 8.2.22.

8.2.33 Appendix R Coordination {3.2.5, 3.2.6, 3.2.7}

Breaker H52 – G05

From the plot on page A53, it can be seen that coordination is not maintained between the gas turbine generator voltage controlled overcurrent relay with the existing setting and any of the downstream transformer high side CO – 9 relays because of the instantaneous element of the COV – 8 relay.

When the instantaneous element of the COV – 8 is reset at twice the maximum fault current from the generator, coordination will be maintained with the 13.8 kV – 480 V transformer high side relays, as shown in the plot on page A54. Coordination does not exist between the COV – 8 relay and the LVSAT high side overcurrent relay even when the COV – 8 instantaneous element is reset because of the relatively high pickup of the LVSAT high side relay.

As shown by the plot on page A55, coordination is not maintained between the gas turbine generator voltage controlled overcurrent relay with the existing setting, and both the safety injection pump motor 1P - 015A overcurrent relay and the transformer 1X - 13 high side overcurrent relay, for a bolted fault on Bus 1A - 05, due to the instantaneous element of the type COV - 8 relay. Coordination is maintained for lower fault levels.

As shown by the plot on page A56, coordination is maintained with the Bus 1A - 05 load breakers at all fault levels with the revised setting for the type COV - 8 relay.

Coordination does not exist between the gas turbine generator voltage controlled overcurrent relay with either the existing or the revised setting, and the Bus 1A - 03 main (normal) feed type CO - 8 overcurrent relay.

Coordination with the load breaker relays at 4.16 kV Buses 1A - 01, 1A - 02, 2A - 01, 2A - 02, 1A - 04, 2A - 04, 1A - 06 and 2A - 06 has not been evaluated, since these buses are not required to be fed by the generator G - 05 for Appendix R related purposes.

Breaker H52 – 10

This breaker is not provided with any overcurrent relaying.

Breaker H52 – 11

Coordination in the overcurrent region is maintained between the CO – 9 relay at breaker H52 – 11 and the downstream main low voltage breaker B52 - 53B for both the existing and new recommended CO - 9 relay time overcurrent settings, as shown on the plots on pages A22 and A23. Coordination can be lost for a bolted through fault with the existing instantaneous setting, but is maintained with the new instantaneous setting.

The existing CO - 9 relay instantaneous pickup is too low, and may result in a loss of coordination with the 480 V side breakers for a fully offset fault. The new recommended instantaneous setting will maintain coordination.

Breaker H52 – 21

This breaker is not provided with any overcurrent relaying.

Breaker H52 – 22

As shown by the plots on pages A36 and A37, coordination is not maintained between the LVSAT high side type CO – 9 relay, and the low side CO – 8 bus feed relay, with the existing relay settings, but coordination would be maintained with the revised relay settings.

Breaker 1A52 – 36

The plots on pages A38 and A39 indicate that coordination is maintained between the Bus 1A - 03 normal feed CO – 8 relay and the downstream motor and transformer feeder relays.

Breaker 1A52 – 57

This breaker is not provided with any overcurrent relaying.

Breaker 1A52 – 60 (2A52 – 73)

As shown by the plots on pages A42 and A43, the CO – 5 relay for the generator G - 01 (or G - 02) feeder breaker does not coordinate with the transformer 1X – 13 (or 2X - 13) high side CO – 8 relay, or the main and bus tie 480 V breakers for this transformer. Coordination is maintained with the safety injection pump motor COM - 5 relay and with the 480 V load breakers.

The analysis in Section 41 of Attachment B indicates that the CO - 5 relay will take about 17 seconds to trip with the generator field forcing current of 736 A. The transformer CO - 8 pickup is 800 A. Therefore the transformer relay will not be picked - up with the field forcing current.

Breaker 1A52 – 66 (2A52 – 67)

The plots on pages A42 and A43 also apply to the CO – 5 relay for the generator G - 02 feeder breaker. Coordination is not maintained with the transformer 1X - 13 (2X - 13) high side relay and with the 480 V main and bus tie breakers. Coordination is maintained with the safety injection pump motor COM - 5 relay and with the 480 V load breakers.

Breaker 1A52 – 80 (2A52 – 87)

As shown by the plots on pages A46 and A47, coordination is maintained between the 51E relay for the generator G - 03 feeder breaker and the downstream relays even with the new recommended lower pickup and time dial setting for the 51E relay.

Breaker 1A52 – 86 (2A52 – 93)

The plots on pages A46 and A47 also apply to the generator G - 04 feeder breaker. Coordination is maintained.

Breaker 1A52 – 58 (2A52 – 75)

The existing instantaneous setting for the transformer 1X - 13 (2X - 13) high side CO – 8 relay is too low, and therefore can result in a loss of coordination with the low side 480 V breakers for a through fault. The recommended higher setting of the instantaneous unit will not involve a trip for a through fault.

The plot on page A14 shows that there is a minor loss of coordination between the transformer 1X - 13 (2X - 13) high side CO – 8 relay, with the new recommended relay setting, and the downstream main and bus tie breakers.

The 480 V bus tie breaker setting must be revised to ensure coordination with the 480 V main breaker.

Although there is a loss of coordination between the high side relay and the downstream 480 V main and tie breakers, coordination will be maintained with the 480 V load breakers because the load breakers coordinate with the main and bus tie breakers.

<u>Breaker 1A52 – 84 (2A52 – 89)</u>

The plots on pages A15 and A16 show that coordination is maintained between the transformer 1X - 14 (2X - 14) high side 51E relay with the existing and new recommended relay setting, and the downstream main breaker.

<u>Breaker 1A52 – 81 (2A52 – 92)</u>

As shown by the plot on page A17, coordination is maintained between the transformer 1X - 06 (2X - 06) high side 51E relay, and the largest MCC breaker.

7. Conclusions

7.1. The addition of 4.16 kV MDAFW Pumps 1P-53 and 2P-53 impacts the following Attachments (see attached revised/added pages for Attachments A, B, C and D) and tables in Sections 8.1.1.1 of the Base Calculation, as well as the addition of new Section 8.2.36:

7.1.1. Attachment A – Coordination Curves (Addition of New Pages A57 and A58 for MDAFW Pump 2P-53 Coordination Curves and revised Pages A41 and A47)

7.1.2. Attachment B – Mathcad Calculations (Revised Sections 52 and 53, Revised Pages B327-B329 for MDAFW Pumps 1P-53 and 2P-53 Motor Relay Pickup and Low and High Instantaneous Settings, New Pages B330-B332 for Revised Section 51 (New Sub-Sections aj, ak and al) MDAFW Pumps 1P-53 and 2P-53 Motor Relay Test Times)

7.1.3. Attachment C – Tabulation of Relay Settings (Revised Pages C7 and C12)

Note: The ground fault relaying chosen for the new MDAFW pump motors matches the existing ground fault relaying settings for motor feeders as described in Section 2.1.3.11 of the base calculation.

The pickup setting of the ITH relay (for Pump 2P-53) is 5 A primary current, and of the GKT relay (for Pump 1P-53) is 30 A primary current. The concern with the low setting of the ITH relays is the possible spurious tripping of the relays during a motor start. Since the existing ground fault relays for other motor feeders have not spuriously operated in the past, the setting of 5 A for the ITH relay and 30 A for the GKT relay will be used.

7.1.4. Attachment D – References (New Pages D45-D56)

7.1.5. Per Section 7.3 and Attachment A Pages A57 and A58, the imposed limitation from Section III.8.06 of Calculation 2004-0002 (Reference 8.2.2) has been met.

7.1.6. Table 8.1.1.1 of the base calculation will be revised to add two line items which read as follows:

Motor	General Acceptance Criteria and Methodology Recommendations				Licensing Related Acceptance Criteria			Calculation Sections	Remarks	Plant Betterment Recommendation	Licensing Issue
	Pickup Setting Acceptable? {2.1.3.2} {2.1.3.10}	High Dropout Acceptable? {2.1.3.3} {2.1.3.10}	Instantaneous Setting Acceptable? {3.1.1} {2.1.3.4}	Locked Rotor Protection Acceptable? {2.1.3.5}	Time Dial Setting Allows the Motor to Start? {3.2.4}	Tap & Time Dial Settings Coordinate with Upstream Relays? {3.2.1} {3.2.5} {3.2.7 (Applies to 1P-015A and P-038A only)}	Is the motor feeder cable provided with short circuit protection? {3.2.3}				
MDAFW Pump 2P-53	Yes	Yes	Yes	Yes	Yes	Yes	Yes	ADD; Sections 7.1.36, 8.2.34 to Base Calculation Page A57 to Base Calculation Section 52 to Attachment B of Base Calculation Attachment C Page C12 to Base Calculation			

Motor	General Acceptance Criteria and Methodology Recommendations				Licensing Related Acceptance Criteria			Calculation Sections	Remarks	Plant Betterment Recommendation	Licensing Issue
	Pickup Setting Acceptable? {2.1.3.2} {2.1.3.10}	High Dropout Acceptable? {2.1.3.3} {2.1.3.10}	Instantaneous Setting Acceptable? {3.1.1} {2.1.3.4}	Locked Rotor Protection Acceptable? {2.1.3.5}	Time Dial Setting Allows the Motor to Start? {3.2.4}	Tap & Time Dial Settings Coordinate with Upstream Relays? {3.2.1} {3.2.6} {3.2.7 (Applies to 1P-015A and P-038A only)}	Is the motor feeder cable provided with short circuit protection? {3.2.3}				
MDAFW Pump 1P-53								ADD: Sections 7.1.37, 8.2.35 to Base Calculation Page A58 to Base Calculation Section 53 to Attachment B of Base Calculation Attachment C Page C7 to Base Calculation			

Installation of Modification EC 13401 is acceptable based on the above conclusions. The protective relaying setpoints and test times have been developed in this minor revision which will allow successful implementation of Modifications EC 13401 and EC 13406.

7.1.7. Section 8.2.34 of the base calculation will be added to read as follows:

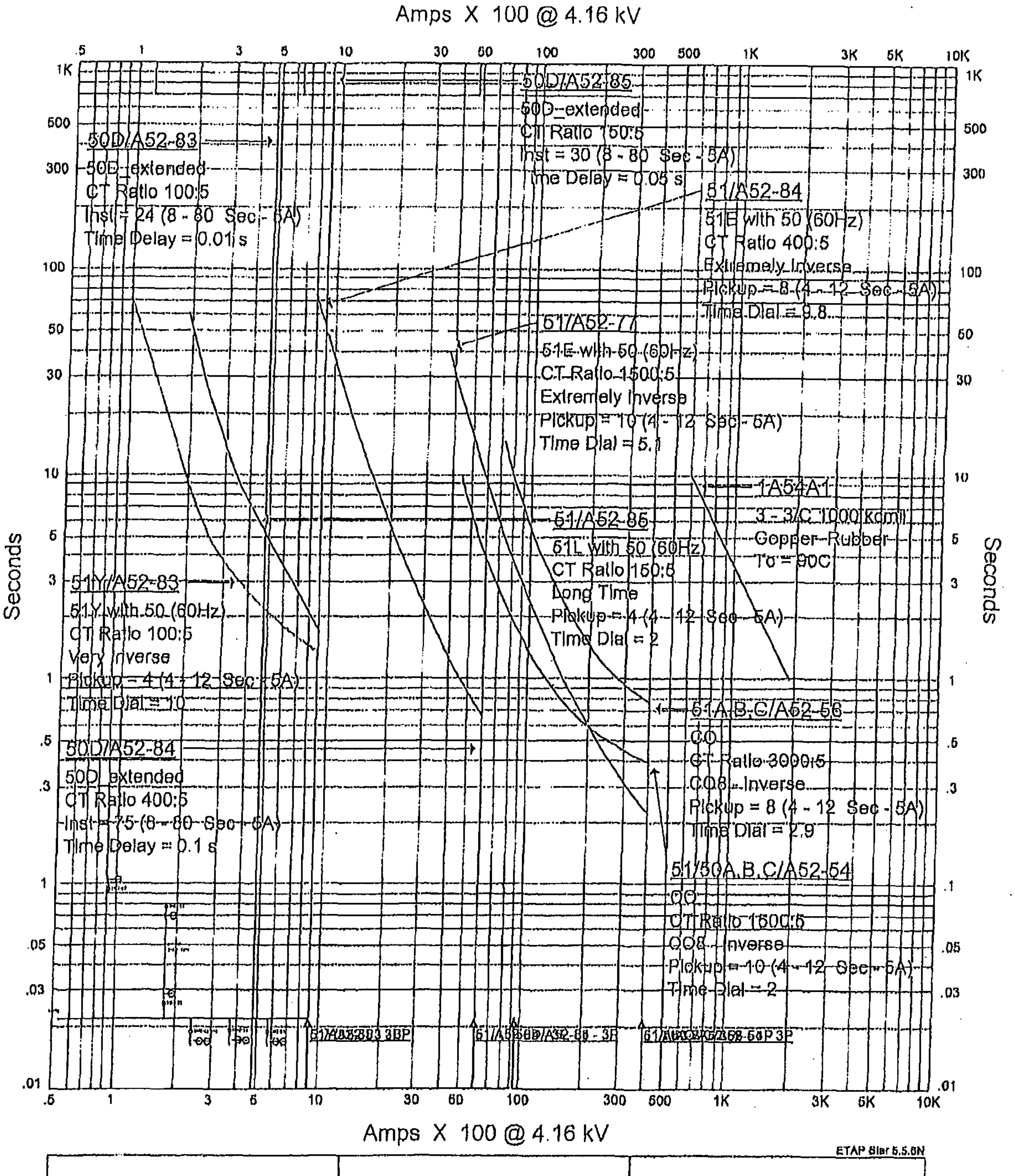
MDAFW Pump 2P-53

The tap, high drop out instantaneous and normal instantaneous settings of the COM – 5 relay are acceptable. See Section 52 of Attachment B.

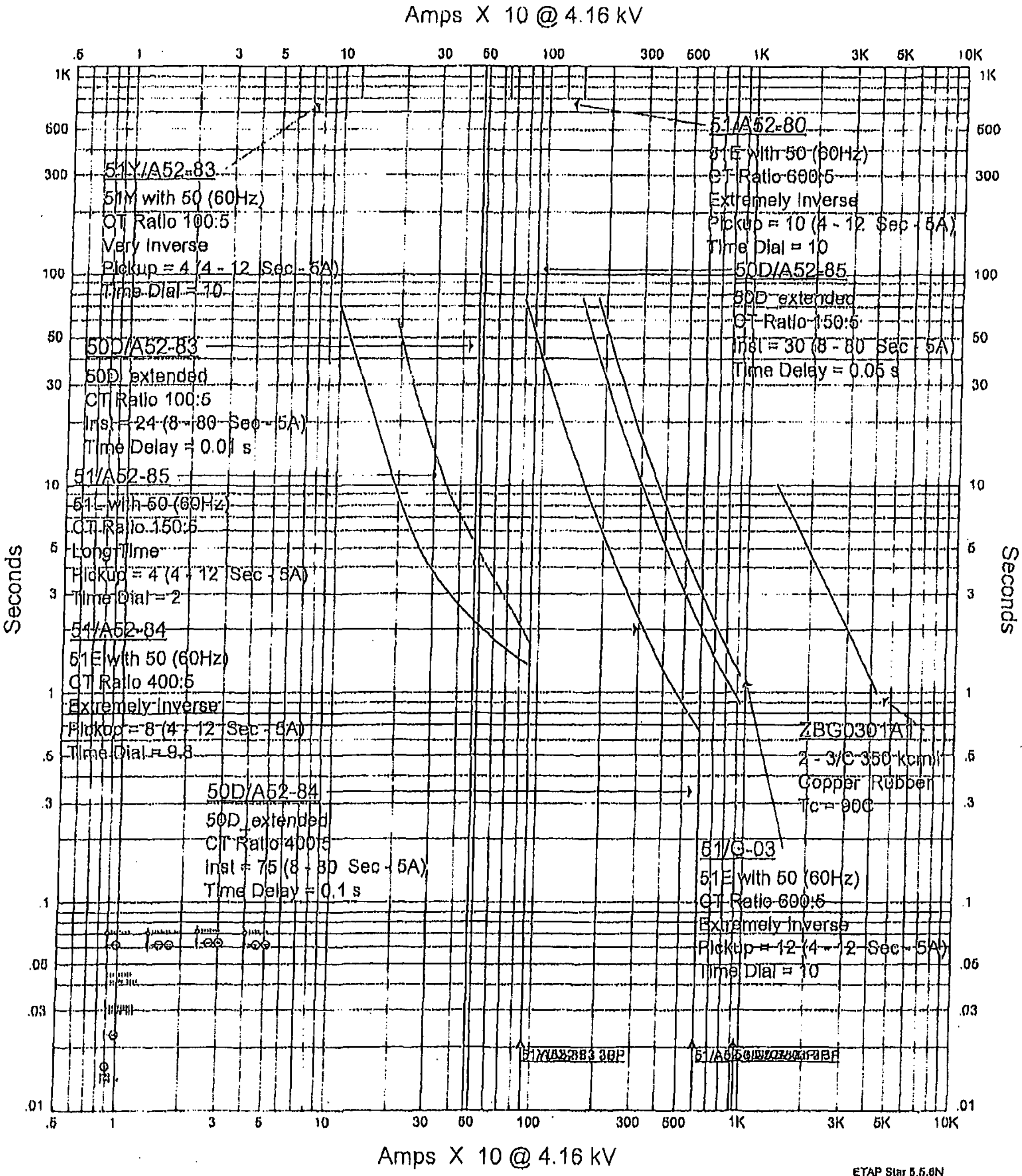
7.1.8. Section 8.2.35 of the base calculation will be added to read as follows:

MDAFW Pump 1P-53

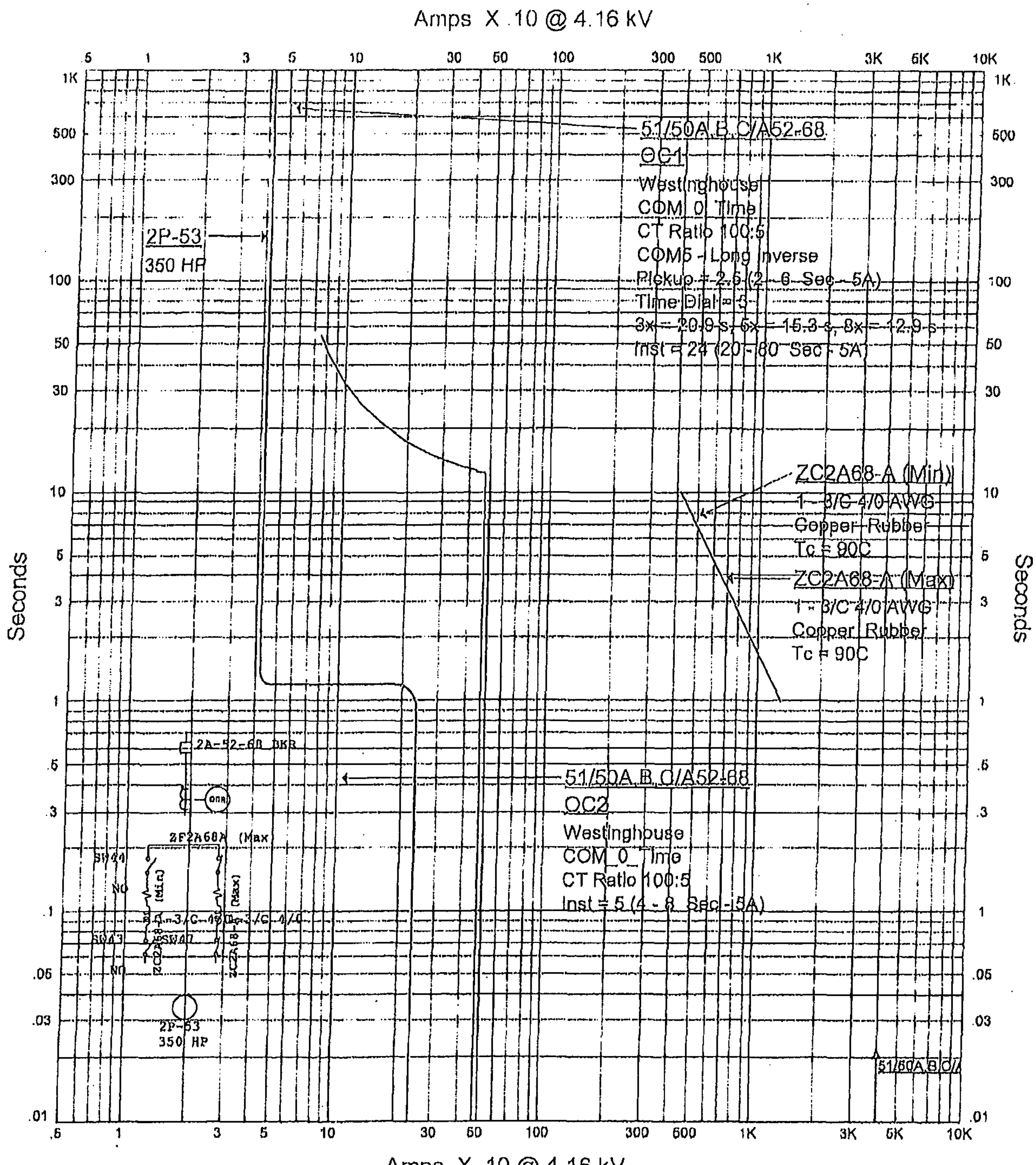
The ABB 49 alarm relay setting, 51Y relay tap, and 50D relay instantaneous settings are acceptable. See Section 53 of Attachment B.



Bus1A-06 from Bus1A-04

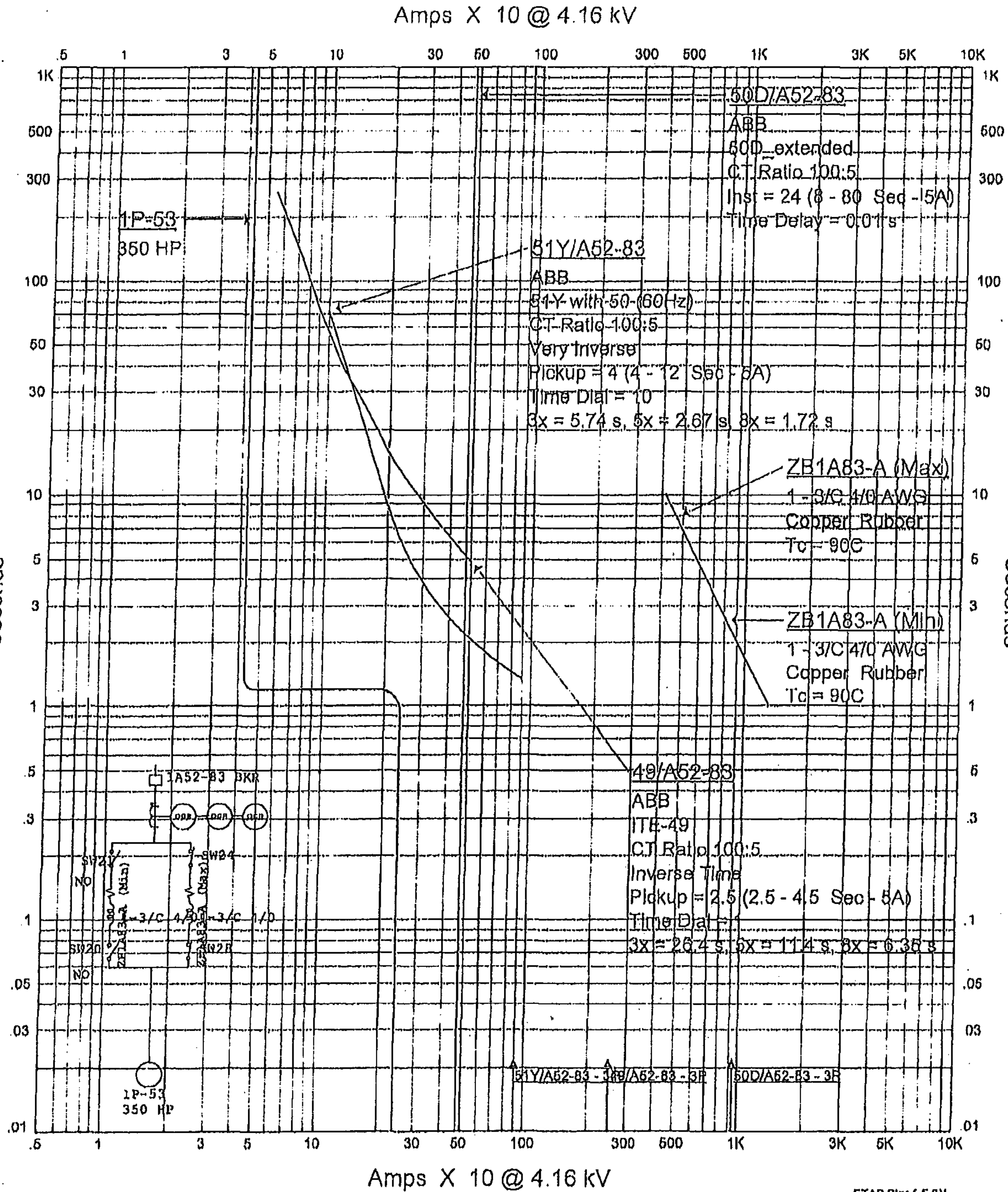


Bus 1A-06 from G-03



Amps X 10 @ 4.16 kV
Seconds
51/50A,B,C/A52-68
OC1
Westinghouse
COM_0_Time
CT Ratio 100:5
COM5 - Long Inverse
Pickup = 2.5 (2 - 6 Sec - 5A)
Time Dial = 3
3x = 20.9 s, 5x = 15.3 s, 8x = 12.9 s
Inst = 24 (20 - 80 Sec - 5A)
2P-53
350 HP
ZC2A68-A (Min)
1 - 3/C 4/0 AWG
Copper Rubber
Tc = 90C
ZC2A68-A (Max)
1 - 3/C 4/0 AWG
Copper Rubber
Tc = 90C
2A-52-68 BKR
51/50A,B,C/A52-68
OC2
Westinghouse
COM_0_Time
CT Ratio 100:5
Inst = 5 (4 - 8 Sec - 5A)
2P-53
350 HP
51/50A,B,C/
ETAP Star 5.5.6N

MDAFW 2P-53


Amps X 10 @ 4.16 kV
50D/A52-83
ABB
50D_extended
CT Ratio 100:5
Inst = 24 (8 - 80 Sec -5A)
Time Delay = 0.01 s
1P-53
350 HP
51Y/A52-83
ABB
51-Y with 50 (60Hz)
CT Ratio 100:5
Very Inverse
Pickup = 4 (4 - 12 Sec - 5A)
Time Dial = 10
3x = 5.74 s, 5x = 2.67 s, 8x = 1.72 s
ZB1A83-A (Max)
1 - 3/C 4/0 AWG
Copper Rubber
Tc = 90C
ZB1A83-A (Min)
1 - 3/C 4/0 AWG
Copper Rubber
Tc = 90C
49/A52-83
ABB
ITE-49
CT Ratio 100:5
Inverse Time
Pickup = 2.5 (2.5 - 4.5 Sec - 5A)
Time Dial = 1
3x = 26.4 s, 5x = 11.4 s, 8x = 6.35 s
51Y/A52-83 - 3P
49/A52-83 - 3P
50D/A52-83 - 3P
Seconds
Amps X 10 @ 4.16 kV
ETAP Star 5.5.0N

MDAFW 1P-53

13.8 KV and 4.16 KV Coordination & Protection
Attachment C - Tabulation of Relay Settings
4.16 KV Bus 1A - 05

Service	CUB. NO	HP OR KW	CKT FLC (AMPS)	CKT LRC (AMPS)		Relay Identification: CT Ratio	MFR.	TYPE	Model or Style No.	RANGE: T.O.C. Unit (Amps)	RANGE: H.D. Inst. Unit (Amps)	RANGE: Instant. Unit (Amps)	Relay Setting – Settings: T.O.C. Pickup (Amps)	Prim Amps	Time Dial	H.D. Inst. Pickup (Amps)	Prim Amps	Inst. Pickup (Amps)	Prim Amps	Relay Trip: T.O.C. % of FLC or L-G Fault	H.D. Inst. % of FLC	Inst. % of LRC or L-G Fault	Test Points: Time Overcurrent Test Current at 2, 3 and 5 Times Pickup			Time Overcurrent Test Time at 2, 3 and 5 Times Pickup			Remarks
Pump Motor 1P-53	1A52-83	350	43	239.34	Phase	100-5 A	ABB	51Y	443T2340	4-12 A			4 A	80 A	10					185 %			8 A	12 A	20 A	17.3 s	5.8 s	2.7 s	
					Ground		ABB	GKT	2021.2115-UL			5-60 A							30 A			3 %							Delay-0.1 s
					Phase	100-5 A	ABB	50D	468T1775			8-80 A						24 A	480 A			200 %							Delay-0.1 s
					Phase	100-5 A	ABB	49	424A0043	2.5-4.5 A			2.5 A	50 A	1					115 %			5 A	7.5 A	12.5 A	58.1 s	26 s	11.4 s	
Station Service Transformer 1X-14	1A52-84	1500 KVA	208 A		Phase	400-5 A	ABB	51E	443T3340	4-12 A			8 A (10 A)	(800 A)	9.8 (4.5)					(384 %)			16A (20A)	24A (30A)	40A (50A)	18s (8.2s)	6.3s (2.7s)	2s (0.85s)	
					Ground		ABB	GKT	2021.2116-UL			5-60 A							30 A			3 %							Delay-0.1 s
					Phase	400-5 A	ABB	50D	468T1775			8-80 A						75 A	5000 A										Delay-0.1 s
Safety Injection Pump 1P-012B	1A52-85	700 hp	86 A	521.5 A	Phase	150-5 A	ABB	51L	443T5340	4-12 A			4 A	120 A	2					140 %			8 A	12 A	20 A	27 s	9 s	3.5 s	
					Ground		ABB	GKT	2020.2115-UL			5-60 A							30 A			3 %							Delay-0.1 s
					Phase	150-5 A	ABB	50D	468T1775			8-80 A						30 A (35 A)	(1050 A)			(201 %)							Delay-0.05 s "New Setting"
					Phase	150-5 A	ABB	49	414A0043	2.5-5A			3.1 A	93 A	1					108 %			6.2 A	9.3 A	15.5 A	58 s	26.3 s	11.5 s	
Emergency Generator G-0K	1A52-86	3560 KVA	494 A		Phase	600-5 A	ABB	51E	443T3340	4-12A			10 A (7 A)	(840 A)	10 (8.5)					(175 %)			20A (14A)	30A (21A)	50A (35A)	18s (16s)	6.4s (5.3s)	2s (1.7s)	"New Setting"

13.8 kV and 4.16 kV Coordination & Protection
Attachment C - Tabulation of Relay Settings
4.16 kV Bus 2A - 05

Service	CUB. NO	HP OR KW	CKT FLC (AMPS)	CKT LRC (AMPS)		Relay Identification: CT Ratio	MFR.	TYPE	Model or Style No.	RANGE: T.O.C. Unit (Amps)	RANGE: H.D. Inst. Unit (Amps)	RANGE: Instant. Unit (Amps)	Relay Setting – Settings: T.O.C. Pickup (Amps)	Prim Amps	Time Dial	H.D. Inst. Pickup (Amps)	Prim Amps	Inst. Pickup (Amps)	Prim Amps	Relay Trip: T.O.C. % of FLC or L-G Fault	H. D. Inst. % of FLC	Inst. % of LRC or L-G Fault	Test Points: Time Overcurrent Test Current at 2, 3 and 5 Times Pickup.			Time Overcurrent Test Time at 2, 3 and 5 Times Pickup.			Remarks
Tie to Bus 2A - 03	2A52 - 76																												
Station Service Transformer 2X - 13	2A52 - 75	1500 kVA	208 A		Phase	400 - 5 A	W	CO - 8	254C800A07	1 - 12 A		6 - 144 A	10 A	800 A	4 (2)			80 A (35 A)	(7920 A)	384 %			20 A	30 A	50 A	8.7s (4s)	3.5s (1.6s)	1.6s (0.8s)	New Setting *
					Ground	50 - 5 A	W	ITH	1955554A			0.25 - 0.5 A						0.5 A	5.0 A			0.5 %							
Safety Injection Pump 2P - 015A	2A52 - 74	700 hp	86 A	521.5 A	Phase	150 - 5 A	W	COM - 5	2859355A12	2 - 6 A	4 - 8 A	20 - 80 A	3.5 A	105 A	3 (2.2)	5 A	150 A	30 A (35 A)	(1050 A)	122 %	174 %	(201 %)	7 A	10.5 A	17.5 A	19s (14s)	12s (8.5s)	8.5s (6.2s)	New Setting *
					Ground	50 - 5 A	W	ITH	1955554A			0.25 - 0.5 A						0.5 A	5.0 A			0.5 %							
Emergency Generator G - 01	2A52 - 73	3560 kVA	495 A		Phase	800 - 5 A	W	CO - 5	1875238A	2 - 6 A		10 - 40 A	3.5 A	560 A	1			None (20 A)	(3200 A)	113 %			7A	10.5 A	17.5 A	5.8 s	3.8 s	2.8 s	New Setting *
Spare	2A52 - 70																												
Spare	2A52 - 69				Phase	400 - 5 A	W	CO - 8	1875277A																				
					Ground	50 - 5 A	W	ITH	1955554A																				
Pump Motor 2P-53	2A52 - 68	350 hp	43 A	239.94	Phase	100 - 5 A	W	COM - 5	2898355A12	2 - 6 A	4 - 8 A	20 - 80 A	2.5 A	50 A	3	4 A	80 A	24 A	480 A	116 %	186 %	200 %	5 A	7.5 A	12.5 A	32.1 s	20.9 s	15.3 s	
					Ground	50 - 5 A	W	ITH	1955554A			0.25 - 0.5 A						0.5 A	5.0 A			0.5 %							
Emergency Generator G - 02	2A52 - 57	3560 kVA	495 A		Phase	800 - 5 A	W	CO - 5	1875238A	2 - 6 A		10 - 40 A	3.5 A	560 A	1			None (20 A)	(3200 A)	113 %			7A	10.5 A	17.5 A	5.6 s	3.8 s	2.8 s	New Setting *

ENCLOSURE 5

NEXTERA ENERGY POINT BEACH, LLC
POINT BEACH NUCLEAR PLANT, UNITS 1 AND 2

LICENSE AMENDMENT REQUEST 261
EXTENDED POWER UPRATE
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION

ADDITIONAL INFORMATION - QUESTION 6 RESPONSE
FUNCTIONAL TIMES FOR ESF EQUIPMENT FOR ACCIDENT ANALYSIS

10 pages follow

Purpose:

The purpose of this calculation is to establish functional times for the actuation of Engineered Safety Features (ESF) equipment (low and high head Safety Injection Pumps, Containment Fan Coolers, and Containment Spray Pumps). These functional times provide basis for the delay time assumptions used in the accident analyses described in the FSAR.

Revision 3 is a total rewrite of the calculation and as such, no revision bars have been used. Changes in 97-0041-01-A have been addressed herein.

Background:

The accident analysis described in Chapter 14 of the FSAR assumes delay times to account for delays associated with the processing of the accident signal, degraded voltage protection scheme to close Emergency Diesel Generator (EDG) output breaker, and the start of the ESF equipment and components to attain design performance. The total delay time assumed for each accident also accounts for appropriate delays for instrumentation logic and signal transport. These delay times were originally estimated in several calculations. This calculation revision consolidates all this information in a single document and provides basis for the delay times used in the accident analysis with and without offsite power as discussed in the FSAR.

Assumptions:

Validated Assumptions

1. It is assumed that the loss of offsite power (LOOP) or initiation of a degraded voltage event will occur coincident with generation of the Safety Injection (SI) signal such that the full emergency diesel generator (EDG) delay will occur after the SI signal as a limiting condition for power availability to the equipment.
   Basis: This assumption is acceptable because it is consistent with the plant design and NRC guidance provided in General Design Criteria [as clarified by SECY-77-439 "Single Failure Criteria" (dated 8/17/1977)] which requires that safety functions for various fluid systems be accomplished assuming unavailability of offsite power, along with the consequences of the initiating event and a coincident single failure. This assumption places full time for the degraded voltage protection scheme to close the EDG output breaker and energize the bus in the functional times determined herein.

2. It is assumed that valves 1(2)SI-00878B and 1(2)SI-00878D are normally open. [IMPOSED CONDITION]
   Basis: This assumption reflects valve positions noted in existing Operations Checklist CL-7A (Unit 1) and CL-7A (Unit 2) and creates an imposed condition for these checklists. Per Reference 11, the valves receive a SI signal to open if they are closed. Based on this assumption, this calculation will not include a stroke time for valves 1(2)SI-00878B and 1(2)SI-00878D (it is noted that IST stroke time testing of these valves is included in procedures IT 210 and IT 215).

3. It is assumed that the stroke time for valves 1(2)SI-00852A and 1(2)SI-00852B is less than or equal to 20.0 seconds. [IMPOSED CONDITION]
   Basis: This is consistent with the maximum allowable stroke time for these valves defined in the Inservice Test Program and establishes an imposed condition for this program.

4. It is assumed that the stroke time for valves 1(2)SI-00860A, 1(2)SI-00860B, 1(2)SI-00860C and 1(2)SI-00860D is less than or equal to 16.5 seconds. [IMPOSED CONDITION]
   Basis: This is consistent with the maximum allowable stroke time for these valves defined in the Inservice Test Program and establishes an imposed condition for this program.

5. It is assumed that the stroke time for valves that must close to isolate non-critical service water loads (SW-02816, SW-02817, SW-02927A, SW-2927B, SW-02930A, SW-02930B, SW-04478, SW-04479, SW-LW-61 and SW-LW-62) and valves that must open to support CFC operation [1(2)SW-02907 and 1(2)SW-02908] is such that the valves will be fully closed or fully open within the time required to sequence and start the Service Water pumps and Containment Fan Coolers fans. [IMPOSED CONDITION]
   Basis: This calculation will determine the maximum allowable stroke time for these valves to meet this criteria and establish an imposed condition for the Inservice Test Program to ensure that stroke time test acceptance criteria incorporates this value. This assumption takes no credit for flow prior to the pump or fan reaching full speed and the valves being full open or full closed. This is conservative since the flow rate is expected to ramp up as the pump is started and valves 1(2)SW-02907 and 1(2)SW-02908 are a gate design which will provide flows close to the full open valves with the valve over half open.

6. It is assumed that the Containment Spray Pump Flow will exceed 1135 gpm. [IMPOSED CONDITION]
   Basis: This assumption bounds the value used in Calculation M-09334-298-ECCS.1 to generate the degraded Containment Spray Pump curves. This assumption creates an imposed condition for the determination of the pump test acceptance criteria in Calculation 96-0233.

7. It is assumed that 14 seconds is sufficient time for the degraded voltage protection scheme to close the EDG output breaker and energize the bus. [IMPOSED CONDITION]
   Basis: This assumption creates an imposed condition for the acceptance criteria used in Calculation 2004-0002. The 10 second EDG starting time required by the original equipment purchase specification for EDGs G01/G02 (Ref. 3) and subsequently used as a design input requirement for the design of the EDGs G03/G04 (Ref. 4) is bounded by this degraded voltage protection scheme delay time.

8. It is assumed that during the Main Steam Line Break accident the Containment Fan Cooler Fans (CFC) will reach full speed within 15.1 seconds. [IMPOSED CONDITION]
   Basis: This assumption creates an imposed condition for the acceptance criteria used in Calculation 2004-0002. The MSLB assumes that Reactor Coolant Pumps (RCPs) are running to make the limiting case. Whenever the RCPs are running, two of the three Containment Fan Coolers need to be running. Since RCPs are running, there is no LOOP and sufficient CFCs are already running. Thus there would be no time delay (0 seconds) to start the CFC fans. However, this calculation uses 15.1 seconds as an imposed condition on Calculation 2004-0002.

Unvalidated Assumptions

None

Acceptance Criteria:

There are no numerical acceptance criteria for this calculation.. The results of this calculation will be used as an input to accident analyses.

[12] This is an imposed condition for Calculation 2004-0002. The value is consistent with the acceleration time provided in Reference 1.

[13] The service water pumps are sequenced in three groups. The sequencer delay time used herein is for the longest delay.

[14] This is an imposed condition for Calculation 2004-0002. This value bounds the acceleration times provided in Reference 1 Attachment C pages 53, 55, 57, 59, 61, 64 and 67 (range of acceleration times from 1.6 to 4.0 seconds).

[15] Due to the way that the Unit 1 ECCS flow model was constructed in Ref. 6, the header on the Unit 1 model states "..Emergency Core Cooling System U2". The header lists the file used to create the run as Eccsr4U1.pdb, which is the Unit 1 model.

Calculation:

Determination of Containment Spray Header Fill Time

Table 1 summarizes the piping volumes for Unit 1 Train A and Unit 1 Train B and Table 2 summarizes the piping volumes for Unit 2 Train A and Unit 2 Train B.

Table 1 - Unit 1 Containment Spray Header Fill Time

	Train A			Train B
	Pipe #	Volume (gal) (Attachment 1)	Pipe #	Volume (gal) (Attachment 1)
	77.00	22.06	62.00	21.93
	78.00	44.51	63.00	55.36
	79.00	492.80	64.00	551.29
	79.10	7.94	64.10	12.95
	79.11	0.00	64.11	0.00
	79.20	7.94	64.20	12.95
	79.21	0.00	64.21	0.00
	79.30	8.18	64.30	10.83
	79.31	0.00	64.31	0.00
	79.40	8.18	64.40	10.83
	79.41	0.00	64.41	0.00
	79.50	8.18	64.50	10.83
	79.51	0.00	64.51	0.00
	79.60	8.18	64.60	10.83
	79.61	0.00	64.61	0.00
	79.70	8.18	64.70	10.83
	79.71	0.00	64.71	0.00
	79.80	8.18	64.80	10.83
	79.81	0.00	64.81	0.00
	79.90	8.18	64.90	10.83
	81.00	27.09	66.00	25.68
Pipe Volume$_{\text{Unit 1, Train A}}$		659.60	Pipe Volume$_{\text{Unit 1, Train B}}$	755.97
Spray Flow (gpm)		1135	Spray Flow (gpm)	1135
Fill Time$_{\text{Unit 1, Train A}}$ (Equation 1)		34.9	Fill Time$_{\text{Unit 1, Train B}}$ (Equation 1)	40.0

Table 2 - Unit 2 Containment Spray Header Fill Time

Train A			Train B	
Pipe #	Volume (gal) (Attachment 2)		Pipe #	Volume (gal) (Attachment 2)
77.00	22.06		62.00	21.93
78.00	44.51		63.00	55.36
79.00	492.80		64.00	495.30
79.10	7.94		64.10	12.95
79.11	0.00		64.11	0.00
79.20	7.94		64.20	12.95
79.21	0.00		64.21	0.00
79.30	8.18		64.30	10.83
79.31	0.00		64.31	0.00
79.40	8.18		64.40	10.83
79.41	0.00		64.41	0.00
79.50	8.18		64.50	10.83
79.51	0.00		64.51	0.00
79.60	8.18		64.60	10.83
79.61	0.00		64.61	0.00
79.70	8.18		64.70	10.83
79.71	0.00		64.71	0.00
79.80	8.18		64.80	10.83
79.81	0.00		64.81	0.00
79.90	8.18		64.90	10.83
81.00	27.09		66.00	25.68
Pipe Volume$_{\text{Unit 2, Train A}}$	659.60		Pipe Volume$_{\text{Unit 2, Train B}}$	699.98
Spray Flow (gpm)	1135		Spray Flow (gpm)	1135
Fill Time$_{\text{Unit 2, Train A}}$ (Equation 1)	34.9		Fill Time$_{\text{Unit 2, Train B}}$ (Equation 1)	37.0

The Unit 1 Train B fill time is the highest of the four flow paths. This bounding Containment Spray Header fill time of 40.0 seconds will be used to determine the functional time.

Determination of Functional Times

The maximum delay time for RHR and SI pump full flow from the detection of the event is determined as follows:

Flow Path	ESF Equipment	SI signal processing time (Seconds) [Margin]	EDG output breaker closure time[19] (Seconds) [Input 1]	Load sequencer time (Seconds)	Load sequencer Uncertainty (Seconds)	Motor acceleration time (Seconds)	Valve Stroke time (Seconds)	Total w/o LOOP (Seconds)	Total With LOOP (Seconds)
LHSI	RHR Pump	2.0	14.0	5.5 [Input 2]	0.27 [Input 3]	1.2 [Input 4]	NA	8.97	22.97
	RHR Valves	2.0	14.0	0 [Input 5]	0 [Input 6]	NA	20.0 [Input 7]	22.00	36.00
HHSI	SI Pump	2.0	14.0	1.0 [Input 8]	0 [Input 9]	8.23 [Input 10]	NA	11.23	25.23

The maximum time delay for the LHSI flow path is that associated with opening valves 1(2)SI-00852A and 1(2)-00852B or 22.0 seconds (36.0 seconds with LOOP). This is rounded up to 23 seconds without LOOP and 37 seconds with LOOP.

The time delay for the HHSI flow path is rounded up to 12 seconds without LOOP and 26 seconds with LOOP.

[19] This value is 0 sec for "without LOOP" scenarios.

The maximum delay time for Containment Spray full flow from the detection of the event is determined as follows:

Flow Path	ESF Equipment	SI signal processing time (Seconds) [Margin]	EDG output breaker closure time (Seconds)[20] [Input 1]	Load sequencer time (Seconds)	Load sequencer Uncertainty (Seconds)	Motor acceleration time (Seconds)	Valve Stroke time (Seconds)	Header Fill Time (Seconds)	Total w/o LOOP (Seconds)	Total With LOOP (Seconds)
Containment Spray	Containment Spray Pump	2.0	14.0	10.25 [Input 11]	0.38 [Input 12]	3.3 [Input 13]	NA	40.0	55.93	69.93
	Containment Spray Valves	2.0	14.0	0 [Input 14]	0 [Input 15]	NA	16.5 [Input 16]	See Note	See Note	See Note

The header fill time for the Containment Spray flow path starts before valves 1(2)SI-00860A, 1(2)SI-00860B, 1(2)SI-00860C and 1(2)SI-00860D are fully open. As such, the total time delay is based on the Containment Spray Pump time delay or 55.93 seconds (69.93 seconds with LOOP). This will be rounded up to 56 seconds without LOOP and 70 seconds with LOOP.

The maximum delay time for Containment Fan Cooler and Service Water pump full flow from the detection of the LOCA is determined as follows:

Flow Path	ESF Equipment	SI signal processing time (Seconds) [Margin]	EDG output breaker closure time (Seconds)[20] [Input 1]	Load sequencer time (Seconds)	Load sequencer Uncertainty (Seconds)	Motor acceleration time (Seconds)	Valve Stroke time (Seconds)	Header Fill Time (Seconds)	Total w/o LOOP (Seconds)	Total With LOOP (Seconds)
Containment Fan Coolers	Containment Fan Cooler Fans	2.0	14.0	46.75 [Input 17]	1.46 [Input 18]	19.42 [Input 19]	NA	NA	69.63	83.63
	Service Water Pump	2.0	14.0	25.75 [Input 20]	0.82 [Input 21]	6.0 [Input 22]	NA	NA	34.57	48.57

The maximum <u>LOCA</u> time delay for the Containment Fan Cooler flow path is that associated with the Containment Fan Cooler Fans or 69.63 seconds (83.63 seconds with LOOP). This will be rounded up to 70 seconds without LOOP and 84 seconds with LOOP.

[20] This value is 0 sec for "without LOOP" scenarios.

The maximum delay time for Containment Fan Cooler and Service Water pump full flow from the detection of the MSLB event is determined as follows:

Flow Path	ESF Equipment	SI signal processing time (Seconds) [Margin]	EDG output breaker closure time (Seconds)[21] [Input 1]	Load sequencer time (Seconds)	Load sequencer Uncertainty (Seconds)	Motor acceleration time (Seconds)	Valve Stroke time (Seconds)	Header Fill Time (Seconds)	Total w/o LOOP (Seconds)	Total With LOOP (Seconds)
Containment Fan Coolers	Containment Fan Cooler Fans	2.0	0	46.75 [Input 17]	1.46 [Input 18]	15.1 [Input 25]	NA	NA	65.31	NA
	Service Water Pump	2.0	0	25.75 [Input 20]	0.82 [Input 21]	6.0 [Input 22]	NA	NA	34.57	NA

The maximum MSLB time delay for the Containment Fan Cooler flow path is that associated with the Containment Fan Cooler Fans or 65.31 seconds. This will be rounded up to 66 seconds.

[21] This value is 0 sec because the MSLB is analyzed "without LOOP" per Assumption 8.

Determination of Valve Actuation Times

Service Water flow path must be fully opened within the time required to sequence and start the pumps and fans. Per Reference 11 the valves receive a signal to open upon receipt of the SI signal and will start to open when the bus is energized. Thus, the required valve actuation time is less than or equal to:

Flow Path	ESF Equipment	Pump/Fan Load sequencer time (Seconds)[22]	Pump/Fan Load sequencer Uncertainty (Seconds)	Motor acceleration time (Seconds)	Required Valve Stroke time (Seconds)
Containment Fan Coolers	Containment Fan Cooler Fans	46.75 [Input 17]	1.46 [Input 18]	15.1 [Input 25][23]	63.31
	Service Water Pump	25.75 [Input 20]	0.82 [Input 21]	6.0 [Input 22]	32.57

The allowable time delay is that associated with start-up of the Containment Fan Cooler Fans. Thus, the valve stroke time must be less than or equal to 63.3 seconds.

[22] The CFC Fans are sequenced in two groups and the Service Water Pumps are sequenced in three groups. The longest sequencer times are used here. It is noted that the normal Service Water CFC flow path is open during the period that the MOVs are stroking.

[23] For the CFC Fans, this value is based on the MSLB accident motor acceleration time which is shorter than that for the LOCA and thus produces a shorter, more conservative, stroke time acceptance criteria.

Results and Conclusions:

The functional times for the actuation of Engineered Safety Features (ESF) equipment (high and low head Safety Injection Pumps, and Containment Spray Pumps) have been determined as follows:

Availability of Offsite Power	Low Head SI	High Head SI	Containment Spray
Without LOOP	23 seconds	12 seconds	56 seconds
With LOOP	37 seconds	26 seconds	70 seconds

The functional times for the actuation of the Containment Fan Coolers for the LOCA and MSLB accidents have been determined as follows:

Availability of Offsite Power	Containment Fan Coolers LOCA	Containment Fan Coolers MSLB
Without LOOP	70 seconds	66 seconds
With LOOP	84 seconds	NA

The functional time for actuation of the Low Head Safety Injection (LHSI), High Head Safety Injection (HHSI) and containment fan cooler flow paths is defined as the time from the moment the SI signal is generated to the moment when the ESF function is accomplished (i.e. full SI flow to the core or full fan cooler heat removal). The functional time for the Containment Spray flow path is defined as the time from the moment the Containment Hi-Hi signal is generated to the time the ESF function is accomplished (i.e., full containment spray flow from the spray nozzles and full fan cooler heat removal). When performing the accident analyses, the delay from the start of the accident until the initiation of the SI or Containment Hi-Hi signal must be added to these functional times to determine the total delay.

The close stroke time for valves SW-02816, SW-02817, SW-02927A, SW-2927B, SW-02930A, SW-02930B, SW-04478, SW-04479, SW-LW-61 and SW-LW-62, and the open stroke time for valves 1(2)SW-02907 and 1(2)SW-02908 must be less than or equal to 63.3 seconds to ensure that valves required to isolate non-critical service water loads are fully closed and valves in the SW flow paths to the CFCs are fully opened within the time required to sequence and start the pumps or fans.

ENCLOSURE 6

NEXTERA ENERGY POINT BEACH, LLC
POINT BEACH NUCLEAR PLANT, UNITS 1 AND 2

LICENSE AMENDMENT REQUEST 261
EXTENDED POWER UPRATE
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION

ADDITIONAL INFORMATION - QUESTION 6 RESPONSE
LOSS OF VOLTAGE AND UNDERFREQUENCY RELAY SETTINGS

42 pages follow

I. GENERAL PURPOSE

The primary purpose of this calculation is to determine the voltage and time delay settings for the Loss of Voltage (LOV) relays associated with the following:

- 4160 V buses 1A01, 1A02, 2A01, 2A02 - Auxiliary Feedwater (AFW) turbine driven pump start and Reactor Coolant Pump (RCP) Trip LOV relays
- 4160 V buses 1A03, 1A04, 2A03, 2A04
- 4160 V buses 1A05, 1A06, 2A05, 2A06
- 480 V buses 1B03, 1B04, 2B03, 2B04, B08, B09

1.0 PURPOSE

The purpose of this calculation minor revision is to determine if proposed time delay settings for the loss of voltage (LOV) relays for safety related buses 1/2-A05/06 (4.16 kV) and 1/2-B03/04 (480 V) of 2.0 seconds and 1.5 seconds, respectively, are acceptable considering drift, uncertainty and loop errors. The proposed time delay settings are selected to support minimum ride through times of 1.4 seconds for the 4.16 kV buses and 1.0 second for the 480 V buses. Selection of allowable value ranges for the time delays will be provided for use in the Technical Specifications.

II. DRIFT, LOOP ERROR AND UNCERTAINTY

II.1 PURPOSE AND SCOPE

The purpose of this calculation section is to present the drift analysis, loop error, measurement uncertainty and calculated setting tolerances that are common to the relay setting analyses performed in the remainder of the calculation.

II.2 METHODOLOGY

The methodology used in this calculation section is not described in the Current Licensing Basis (CLB) for PBNP.

II.2.01 Determination of Relay Uncertainties

The methodology presented here is based on the guidance of Design Guide DG-I01 "Instrument Setpoint Methodology" (Reference X.4.02).

Note: Rounding the setpoints is performed by rounding up on lower limits and rounding down on upper limits for as-left calibration settings. This ensures settings are conservative relative to safety and operability limits.

The following discussion will identify whether each error contributor is applicable, random, nonrandom, independent, and/or a direction bias for the various relay types and elements evaluated in this calculation. With the exception of the PT correction factor, the error contributors will be expressed in percent of relay setting (rather than in percent of relay setting span), to be consistent with the manufacturer's published relay accuracy (Reference X.11.01).

A generalized view of the voltage and frequency relay sensing loop elements is shown in Figure 1.

Section II – Drift, Loop Error and Uncertainty

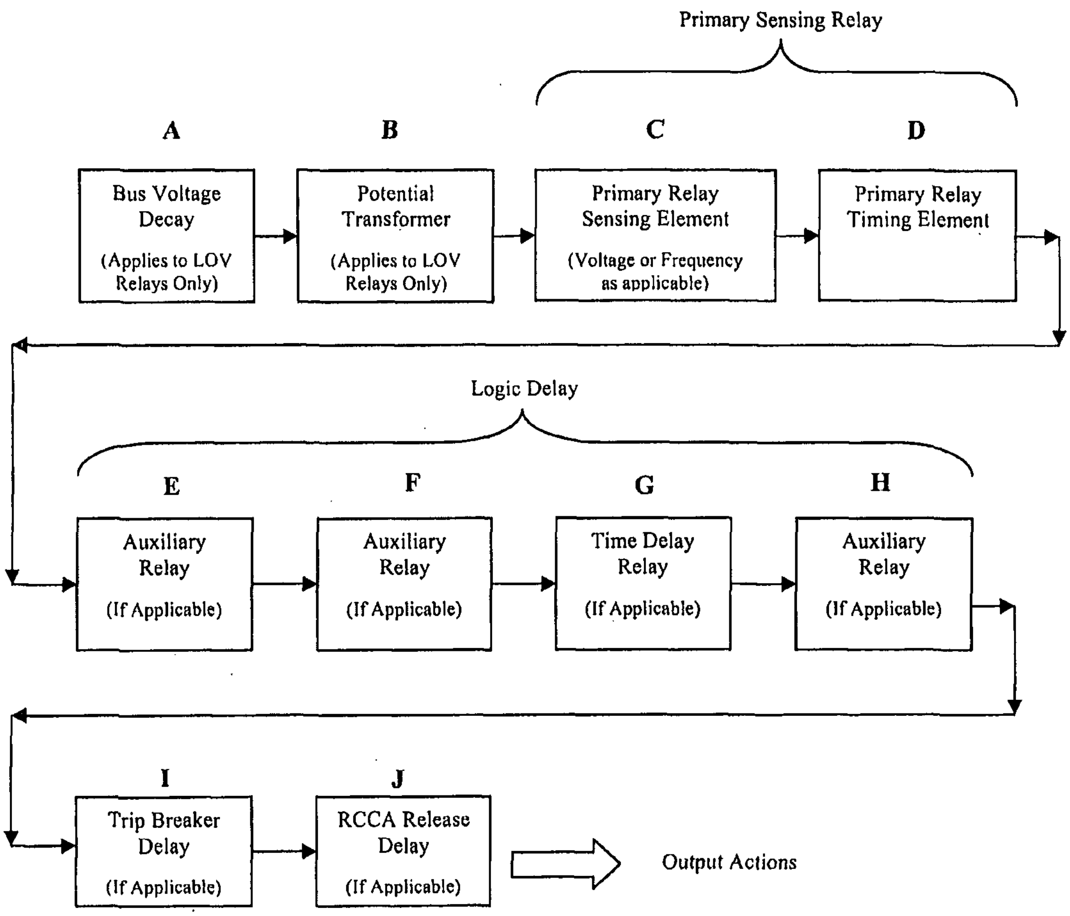


Figure 1

The voltage decay in Block A is developed conservatively in the calculation sections that make use of it. Since it is not subject to calibration or M&TE error, it is not discussed further in this calculation section.

The voltage error associated with Block B is conservatively applied algebraically as a bias outside the loop error calculations. It is applied in the sections that make use of it and is not discussed further in this calculation section.

The error contributors associated with Blocks C and D are identified based on the guidance in DG-I01 (Reference X.4.02).

For Blocks E, F, and H through J, error analysis is not done since these blocks represent devices with fixed (non-adjustable) operating characteristics. The manufacturers of these devices provide a maximum operating time that includes all applicable uncertainty. Since these devices are not calibrated, errors associated with drift and M&TE are not applicable. The time delays for these devices are considered

Section II – Drift, Loop Error and Uncertainty

in the following calculation sections as they apply. The devices in Blocks E, F, and H through J are not discussed further in this calculation section.

The various relay loops evaluated in this calculation are tabulated below with the applicable blocks identified:

Buses	Relay Type	Function	Applicable Blocks									
			A	B	C	D	E	F	G	H	I	J
1A01, 1A02, 2A01, 2A02	ITE—27D	RCP LOV	X	X	X	X	X	X			X	X
1A01, 1A02, 2A01, 2A02	CV-7	AFW LOV	X	X	X	X	X		X	X	X	
1A01, 1A02, 2A01, 2A02	KF	RCP Under Frequency			X	X	X				X	
1A03, 1A04, 2A03, 2A04	CV-7	LOV	X	X	X	X	X				X	
1A05, 2A05	ITE—27D	LOV	X	X	X	X	X	X	X	X	X	
1A06, 2A06	ITE—27D	LOV	X	X	X	X	X		X	X	X	
1B03, 1B04, 2B03, 2B04	ITE—27D	LOV	X	X	X	X	X	X			X	

II.2.02 Error Contributors

II.2.02.1 Accuracy: The manufacturer gives the relay setting accuracy for some relays as repeatability. Because the relay setting for the drop-out and pickup are each approached from only one direction, linearity and hysteresis are not included in the relay accuracy term. Note that when the drift is determined by as-left / as-found calibration data, relay accuracy is included as part of the drift term. When the drift is determined by statistical analysis, the drift is conservatively substituted for accuracy when determining setting tolerance (ST). Relay accuracy is classified as a random error, and will be combined by the Square Root of the Sum of the Squares (SRSS) method (Reference X.4.02).

II.2.02.2 Primary Element Accuracy (Potential Transformer): The LOV relays sense a voltage between 0 – 150 Vac, therefore it is necessary to a have a potential transformer (PT) to convert a high voltage signal to a low voltage signal. As described in IEEE Std. C57.13-1993 (Reference X.2.01), the voltage on the secondary side of a potential transformer is a function of the burden (load) on the PT and is described by the PT's accuracy class or provided by the manufacturer. Because a PT has a fixed turns ratio, the PT error is limited to the correction applied to the turns ratio as a result of the secondary side burden. This error is a bias, because the burden shifts the PT output in only one direction for a given burden. The error of the PT will be expressed as PT^- for the largest error in the negative direction and PT^+ for the largest error in the positive direction. The error of the PT will be accounted for in the conversion from the high voltage signal to the low voltage signal and from the low voltage signal to the high voltage signal. The PT error is applied to the signal before applying the total loop error because the PT error is based on the turns ratio of the transformer and connected burden, and is unrelated to the total error of the LOV relays. The error for the PT is classified as a non-random process error and will be based on the accuracy assigned to the PT by the manufacturer. PT performance is not significantly affected by environment factors, thus no additional error for the PTs will be introduced.

II.2.02.3 Drift: Relay setpoint drift applies as a random uncertainty for both drop-out and pickup settings. Drift can be calculated or given by the manufacturer. No manufacturer drift value is available, but relay calibrations performed since 1987 provide as-left / as-found data that can be used to calculate the drift using statistical methods described in Appendix H of DG-I01 (Reference X.4.02). See Section II.2.03.1 below for more explanation of this method of determining drift. Relay drift is classified as a random error, and will be combined by the Square Root of the Sum of the Squares (SRSS) method (Reference X.4.02).

II.2.02.4 M&TE: The manufacturer of the M&TE provides an uncertainty associated with frequency of calibration of the M&TE. The uncertainty of the M&TE is random and independent in consideration of the LOV relay setpoint. However, when relay setting drift is determined using as-left/as-found calibration data, M&TE accuracy is included as part of the calculated drift term, and does not need to be accounted for separately (as long as the M&TE uncertainty is less than or equal to the M&TE used to perform the calibrations).

II.2.02.5 Setting Tolerance: The setting tolerance establishes a sufficient range to allow the technician to set the relay. Setting tolerance (ST) is expressed as a random (±) value around an ideal setting, although the tolerance can also be asymmetric (e.g., +2, -0). The tolerance range is established based on the device accuracy, MT&E accuracy used to calibrate the relays, the limitations of the technician in adjusting the device, and the need to minimize calibration and testing time. When drift is determined by as-left/as-found statistical methods, setting tolerance is treated as a separate random error contributor to total loop error.

II.2.02.6 Power Supply Effect: The power supply effect is the effect of control voltage variations on the relay settings. Some manufacturers provide an uncertainty for their relays due to control voltage. This effect is assigned a value by the relay manufacturer separate from relay accuracy and is considered random and independent of other error terms.

II.2.02.7 Temperature Effect: Some manufacturers provide an uncertainty for their relays due to temperature. This effect is assigned a value by the relay manufacturer separate from relay accuracy and is considered random and independent of other error terms. As-left/as-found calibration data will account for some of this effect, however the temperature recorded during performance of calibrations does not cover the complete range of operation. Therefore, it is conservative to apply the full temperature effect to the overall relay uncertainty separate from the drift tolerance.

Section II – Drift, Loop Error and Uncertainty

II.2.02.8 Humidity Effect: No uncertainty due to humidity is considered in the total relay error (Assumption II.4.02).

II.2.02.9 Radiation Effect: No uncertainty due to the radiation effect is considered in the total relay error (Assumption II.4.03).

II.2.02.10 Seismic or Vibration Effect: There is no uncertainty due to seismic or vibration effect considered in the total relay error (Reference X.4.04).

II.2.03 Drift Analysis

II.2.03.1 As-found/as-left calibration data will be statistically analyzed to establish the drift error on the relays with adjustable settings. The general approach in performing a statistical analysis of the data is provided in Appendix H of Design Guide DG-I01 (Reference X.4.02). The following is a summary of the steps performed in the statistical analysis:

a. As-left and as-found values for the LOV relay drop-out settings were compiled from historical plant relay calibration data collected between 1987 and 2007. The raw data for each of the 8 LOV relays were tabulated in Attachment B, including as-left and as-found drop-out values and as-left and as found dates.

b. From the drop-out values and dates, the number of days between calibrations and the measured drift over the interval was determined on the spreadsheet. To make the sample representative of the nominal 18-month calibration interval, only those as-left/as-found pairings that were measured within - 25% of 18 months and 24 months (between 405 and 730 days apart) were analyzed.

c. From the population of as-left/as-found pairings that were suitable for analysis, the standard deviation was calculated using the Excel STDEV function.

d. The standard deviation was then multiplied by a factor based on the sample size to determine a 95% confidence level drift value.

e. DG-I01 provides the method of identifying and removing "outliers" from the sample population.

f. The data set was tested for "normalcy" by determining skewness and kurtosis using the procedure in DG-I01 Appendix H (Reference X.4.02).

g. If the data set failed the "normalcy" test, the DG-I01 Appendix H (Reference X.4.02) approach could not be used and in order to be conservative the largest drift error found in the data set would be used.

The Software Quality Assurance program does not apply to the Microsoft Excel spreadsheet used for the drift analysis because Step 2.4.7 in Reference X.4.01 (FP-IT-SQA-01 "NMC Software Quality Assurance (SQA) Program"), states that the SQA program does not apply for "Application software for which the output is validated and documented as having been validated each time the application software is used." The results of the Excel application are independently verified as part of the independent technical review of this Calculation.

II.2.04 Determination of Total Loop Error

The total loop error (TLE) includes all relay uncertainties (except the PT ratio correction) and is determined in accordance with the requirements of Design Guide DG-I01 (Reference X.4.02). The setpoint methodology at PBNP utilizes a combination of the straight sum and the square root sum of the square (SRSS) plus algebraic approaches. The error effects are evaluated based on known behavior and are characterized as independent, dependent, random or non-random. The random elements of uncertainty are combined by SRSS, and any non-random uncertainties (commonly known as bias) are added algebraically (straight sum) to the SRSS result according to sign. The uncertainty equation for each instrument is based on the characteristics of each applicable element of uncertainty. Therefore, the following general equation is utilized to calculate the positive (TLE^+) and negative (TLE^-) total loop uncertainty and is developed in design guide DG-I01 (Reference X.4.02).

$$TLE = \pm\sqrt{A^2 + B^2 + (C + D)^2} \pm \Sigma|X| + \Sigma Y - \Sigma Z$$

Where:

A, B =	Independent and Random uncertainty errors
C, D =	Dependent and Random uncertainty errors
X =	Non-random error with unknown sign
Y =	Non-random positive bias
Z =	Non-random negative bias

II.2.05 Determination of Setting Tolerance

The setting tolerance (ST) establishes a range about the ideal field trip setpoint (FTSP) for the technician to set the relay. The setting tolerance is determined to be equal to or greater than the SRSS of the relay accuracy and the M&TE accuracy. When the drift is determined by statistical analysis of as-found/as-left calibration data, the drift will be substituted for the relay accuracy. The setting tolerance in percent of setting is determined as follows:

$$ST = \pm\sqrt{a^2 + m^2}$$

Where:

a =	Relay accuracy (or drift if determined through statistical analysis)
m=	M&TE accuracy

3.0 ACCEPTANCE CRITERIA

3.1 The time delay element settings for the LOV relays for 4.16 kV safety buses A05 / A06 and 480 V safety buses B03 / B04 shall be short enough to ensure that the LOV logic actuates and initiates the required actions in time to support the actuation times used in the applicable accident analyses (Reference X.8.05.6 of Revision 0 of this calculation).

3.2 The time delay setpoint of the LOV relay logic scheme must be long enough to prevent spurious actuation during transients imposed by offsite power disturbances. The LOV relay time delay required for this transient is defined by PBNP letters (Attachment C & D) as 1.4 seconds for 4.16 kV safety buses (A05 and A06) and 1.0 second for 480 V safety buses (B03 and B04). To remain within the Transmission System Operator voltage analysis supporting Reference 5.2 of this minor revision, a dual unit trip should not be caused by a single transient disturbance. Therefore, the LOV relays should not prematurely trip upon these disturbances. This criterion is based on an implicit assumption made in FSAR Chapter 8 (Reference X.8.05.1).

3.3 The time delay element settings for the B03/B04 480 V buses must be short enough to ensure that the 480 V stripping is initiated before the EDG breaker close permissive occurs.

3.4 The time delay setpoint of the EDG Close Timer (follower) relay must be long enough to ensure that the safe closure thresholds as established in calculation 2005-0007 (Reference X.1.07 of Revision 0 of this calculation) are reached before the EDG breaker close permissive occurs.

3.5 The time delay setpoint of the EDG Close Timer (follower) relay must be long enough to ensure that the 4.16 kV stripping is initiated before the EDG breaker close permissive occurs.

3.6 The time delay setpoint of the EDG Close Timer (follower) relay must be short enough to ensure that the EDG breaker close permissive occurs in time to support the actuation times used in the applicable accident analyses (Reference X.8.05.6 of Revision 0 of this calculation).

6.0 ASSUMPTIONS

6.1 All assumptions in the existing base calculation 2008-0005 are valid for this minor revision.

II.4 ASSUMPTIONS

Validated Assumptions

II.4.01 It is assumed that the PTs feeding the 480 V buses have a ratio error (correction) of 0.997 to 1.003 for the burdens currently imposed upon them.

Basis: The Westinghouse PT data in Reference X.10.13 indicates that the transformer is rated 0.6 for a class W (12.5 VA) burden, and that the transformer will maintain 0.3 metering accuracy for most single meter applications. For the 480 V buses, the relay burden is three ITE-27D relays at 1.2 VA each plus a voltmeter that can be switched off or on to any single phase (References X.5.30, X.5.32, X.5.34 and X.5.36). This burden is shared among three PTs. The meter is a Westinghouse H-252 series horizontal edgewise meter (References X.5.57 through X.5.59 and X.11.05). The manufacturer's published burden for these meters is 0.096 VA at 120 Vac (Reference X.10.14). The burden for a Westinghouse K-241 circular scale voltmeter similar to those in the 4.16 kV systems at PBNP is given as 1.92 VA at 120 Vac (Reference X.10.14). The total burden on a phase with the voltmeter switched on is $1.2 + 0.096 \approx 1.3$ VA. If "most single meter applications" as stated by the PT manufacturer includes a single circular scale meter, we can see that the burden of the relay plus the edgewise meter is less than a very common single meter application. In addition, the burden is only $\left(\frac{1.3\,\text{VA}}{12.5\,\text{VA}}\right) \times 100 = 10.4\%$ of the burden that the transformer will support for an accuracy of 0.6%. Therefore, it is reasonable to assume that the PTs will maintain a metering accuracy of ± 0.3% for this application.

II.4.02. It is assumed that there is no uncertainty due to humidity changes.

Basis: There is no uncertainty due to humidity changes provided by the relay manufacturer. The relays have performed well under varying humidity conditions in the switchgear rooms for 10 years (Reference X.9). Because the as-left/as-found calibration data includes any effect caused by these humidity variations, no separate uncertainty due to humidity is considered.

II.4.03 It is assumed that there is no uncertainty due to the radiation effect.

Basis: The relays are located in the turbine building or control building outside containment and thus will not experience any significant radiation exposure greater than background, even under accident conditions. Therefore, no radiation effect is considered.

II.4.04 It is assumed that the LOV relay time delay setpoints are calibrated using a meter with an accuracy of ±0.01 % of reading or better.

Basis: The accuracy of the Multi-Amp TV-2 is ±0.0001 sec or 0.0025% of reading (Reference X.11.10). This device is referenced in various PBNP procedures for use in time delay setting. The procedures require use of this meter or equivalent (References X.6.01, X.6.12). This value was rounded up for conservatism and to allow for substitution of M&TE.

II.4.05 It is assumed that the uncertainty of the M&TE utilized to calibrate the frequency settings of the UF relays will be ± 0.07% or less.

Basis: The M&TE currently required by calibration procedure is a Multi-Amp TV-2 or equivalent, which has an uncertainty of 25 Hz per 1,000,000 Hz or ±0.0025% as an acceptance criterion to calibrate the M&TE (References X.6.01, X.6.12 and X.11.10). Measuring 55 Hz on a 200 Hz range with a resolution of 0.01 Hz, the Fluke 8060A, which has an accuracy of ±0.05% of reading + 1 digit (Input II.5.12), this translates to:

$$\left(\frac{55\,\text{Hz}\,(0.0005)+0.01\,\text{Hz}}{55\,\text{Hz}}\right)\times 100 = 0.068\%,$$

which is conservatively rounded up to 0.07%.

II.4.06 It is assumed that the uncertainty of the Fluke 8505A M&TE utilized to calibrate the drop-out voltage setting of the LOV relays is ±0.105% or less.

Basis: The M&TE currently required by calibration procedure is a Fluke 8505A or equivalent, which has an uncertainty of 0.105% when calibrated on a 12 month cycle (References X.11.02 and X.9). Therefore the M&TE uncertainty will be equal to or less than ±0.105% when calibrating the drop-out voltage setting of the LOV relays. The calibrations utilize the 100V range, for which a maximum full scale reading is 160.000V, to measure an approximate 120V signal. This includes approximately an additional 0.005% error to account for the number of counts with a 1 mV resolution.

II.4.07 It is assumed that the cable and fuse impedance has a negligible effect on the burden and ratio correction factor of the potential transformer supplying the LOV relays.

Basis: The highest burden on the potential transformer, when the relay is required to operate, is 53.4 VA (or approximately 0.445 amps at 120 V nominal voltage) (See Inputs II.5.01.2, II.5.02.2, II.5.03.2, II.5.04.2 and II.5.05.2). The voltage drop across the cables is negligible due to the short cable length (cables remain in the switchgear), the maximum fuse current of 0.445 Amps and the insignificant fuse resistance. Therefore, the cable and fuse impedance have a negligible affect on the burden and ratio correction factor of the potential transformer.

II.4.08 It is assumed that there is no uncertainty due to the seismic or vibration effect for the CV-7, ETR, ITE-27D and KF relays.

Basis: There is no uncertainty due to seismic or vibrational effect provided by the relay manufacturer. Specific setpoints that require evaluation for seismic effects are those that are credited as primary trips for accidents/transients that could credibly occur as the result of a seismic event. These setpoints are found in Table 2.2.1 of the

Seismic Evaluation Report, USNRC Generic Letter 87-02, USI A-46 Resolution (Reference X.4.04) and are listed below.

FSAR Section	Accident/Transient	Primary Reactor Trip Variable
14.1.3	Rod Cluster Control Assembly (RCCA) Drop	Low Pressurizer Pressure
14.1.6	Reduction in Feedwater Enthalpy	None Required
14.1.7	Excessive Load Increase	None Required
14.1.8	Loss of Reactor Coolant Flow	Low RCS Flow
14.1.9	Loss of External Electrical Load	Over Temp – Delta T High Pressurizer Pressure Low-Low S/G Level
14.1.10	Loss of Normal Feedwater	Low-Low S/G Level
14.1.11	Loss of All AC Power due to Auxiliaries	Low-Low S/G Level
14.2.5	Stuck Open Steam Dump or S/G Safety Valve	None Required

Since the trip setpoints, for the CV-7, ITE-27D and KF relays in this calculation are not shown in the above table, they and their associated time delay (ETR) relays do not need to include a seismic uncertainty term because their function is not required during or following a seismic event. The normal vibrational effect is accounted for by the drift calculated from the as-left/as-found data and therefore no additional uncertainty is necessary to account for this effect.

II.4.09 It is assumed that the nominal voltage and time tolerances for temperatures in the 20°C to 40°C range is consistent for the LOV ITE-27D relays.

Basis: Issue E of the ITE-27D manual supports the nominal 0.5 V and ± 5% time tolerances for temperatures in the 20°C to 40°C range (Reference X.11.07). Environmentally qualified equipment in the Turbine Building is located in two general areas, near the Feedwater Regulating Valves and at the Condensate Storage Tanks. Plant operators estimated that the summertime temperature near the Condensate Storage Tanks was a maximum of 85°F and the summertime temperature near the Feedwater Regulating Valves was a maximum of 95°F (the temperature near the Feedwater Regulating Valves was higher due to the number of steam and feed pipes in the area). Actual plant operating temperatures gathered through temperature monitoring at the Turbine Building (Condensate Storage Tank area and Main Feedwater Regulating Valve area) ranges from 77.5°F to 100.5°F. (Reference X.4.05).

II.4.10 It is assumed that the maximum dc supply voltage at the relays is 134.5 Vdc, which occurs when the system is fed from the chargers.

Basis: The relays use 125 Vdc control power from DC buses that are normally supplied by voltage-regulated battery chargers. The calibration procedure for battery chargers D-07, D-08 and D-09 calls for the output voltage to be set in the range of 132.5 to 133 Vdc (Reference X.6.26). The calibration procedure for battery chargers D-107, D-108 and D-109 calls for the output voltage to be set in the range of 133.5 to 134.5 Vdc (Reference X.6.27). Therefore, it is conservative to assume that the maximum operating voltage for all relays is 134.5 Vdc.

II.4.11 It is assumed that the power supply effect on the voltage setpoint on the ITE-27D relays is -0.2V/+0.3V over the expected voltage range of 102 – 134.5 Vdc at the relays.

Basis: The maximum supply voltage to the ITE-27D relays is 134.5V (Assumption II.4.10) and the minimum is 102V (Reference X.1.03, X.1.04). Based on Reference X.10.02, a -0.2V change is expected for a 25V drop from nominal and a +0.3V change for a 15V increase from nominal is typical for these relays. This corresponds to a range of 100 – 140 Vdc, which bounds the range of terminal voltages expected at the relays.

II.4.12 It is assumed that the setpoint for the B03/B04 ITE-27D relays voltage elements is 60 V for the purposes of determining M&TE accuracy for these relays.

Basis: The minimum allowable voltage setting for these relays in the Technical Specifications (Reference X.8.03) is 256 V ± 3%; the actual setting will be higher. 256 V is more than 50% of the nominal 480 V bus voltage. 60 V represents 50% voltage on the relay's 120 V base. This value appears in the denominator of a percentage computation in the M&TE determination, so a smaller value is conservative since it will produce a larger M&TE error value.

II.4.13 It is assumed that the reference accuracy of ± 5% applies for the Agastat ETR relays evaluated in this calculation.

Basis: The ± 5% tolerance applies to a temperature range of 70 °F to 104 °F, while a tolerance of ± 10% applies for temperatures outside this range out to a range of 40 °F to 156 °F (Reference X.11.01). These relays are exposed to a temperature range of 65 °F to 115 °F (Inputs II.5.01.1, II.5.02.1, II.5.03.1, II.5.04.1 and II.5.05.1). This is only slightly outside the range that the manufacturer states where the ± 5% tolerance applies. There is insufficient calibration history data at the time settings used on the relays evaluated in this calculation to support a statistically valid drift analysis. Drift analysis of similar Agastat ETR relays shows a drift of 2.75% (Reference X.1.01). These ETR relays are in the same switchgear environments and similar applications to the relays evaluated in this calculation, but are set for a much longer delay. Therefore, the drift analysis done on these relays cannot be applied directly to the relays evaluated here. The drift analysis shows that the drift of the ETR relays remains well below the manufacturer's stated ± 5% tolerance. Therefore, the ± 5% tolerance is considered adequately conservative for the purposes of this analysis.

II.4.14 It is assumed that the setpoint for the Agastat ETR relays is 2.5 seconds for the purposes of determining M&TE accuracy of the Fluke Scopemeter 123 for these relays.

Basis: The minimum as left value for these relays from the current procedures is 2.85 seconds (References X.6.02, X.6.03, X.6.13 and X.6.14). This value appears in the denominator of a percentage computation in the M&TE determination, so a smaller value is conservative since it will produce a larger M&TE error value.

Unvalidated Assumptions

None.

6.2 The drift for a replacement 4160 V or 480V LOV relay with a time delay range of 1.0 to 10.0 seconds is assumed to approximate the drift for the existing relay.

VII. A05/A06 BUS LOV RELAY SETTING

VII.1 PURPOSE AND SCOPE

The purpose of this calculation section is to determine the dropout voltage and time delay settings for the loss of voltage relaying scheme for 4.16 kV buses 1A05, 1A06, 2A05, and 2A06.

The scope of this calculation section includes settings for the LOV relays and the EDG close delay (follower) time delay relays. The specific relays whose settings included in the scope of this calculation section are tabulated below:

Function	Relays IDs
LOV	1(2)-271/A05, 1(2)-272/A05, 1(2)-273/A05, 1(2)-271/A06, 1(2)-272/A06, 1(2)-273/A06
EDG Close Delay (Follower)	1(2)-62-4/A05, 1(2)-62-5/A05, 1(2)-62-4/A06, 1(2)-62-5/A06

A block diagram of the logic scheme evaluated in this section is presented in Figure 9:

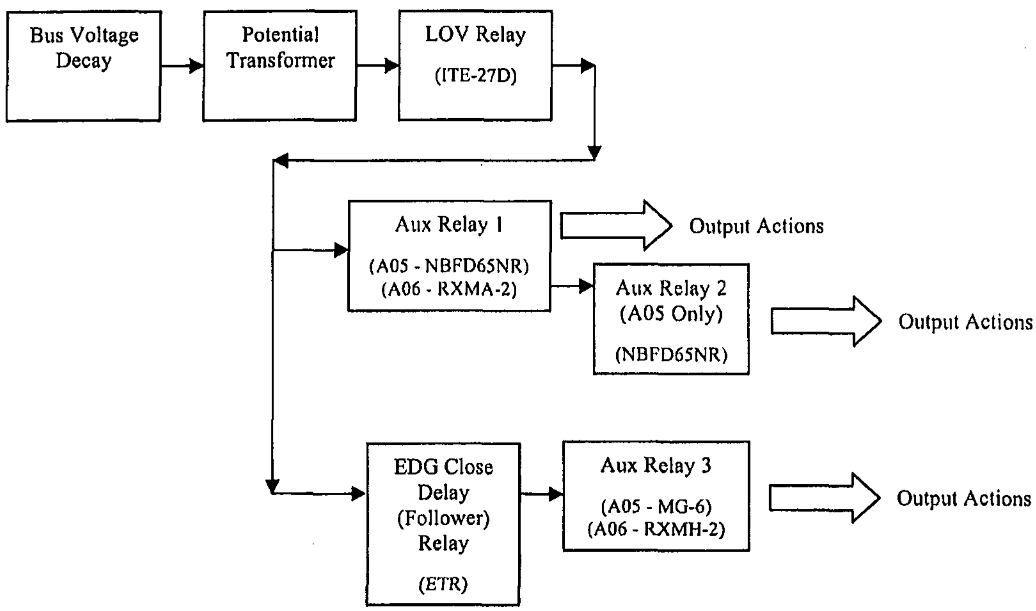


Figure 9

In this scheme, Aux relay 1 trips the incoming 4.16 kV feed breaker to A05/A06, and starts the EDGs associated with the bus. Aux relay 3 makes up a close permissive for the EDG output breaker. Both the permissive from Aux relay 3 and the EDG ready to load permissive must be made up for the EDG breaker to close (References X.5.53 and X.5.54).

Section VII – A05/A06 Bus LOV Relay Setting

The voltage and time delay settings for the relays in this scheme must be selected in conjunction with the voltage and time delay settings for the 480 V LOV relays at buses B03/B04 (Section VIII) to ensure the following, whether the EDGs are running prior to the LOV or not:

- The EDGs will be started and their output breakers can be closed onto the bus in 14 seconds or less (The accident analyses in Reference X.8.05.6 assume 15 seconds, but Reference X.1.06 reduces this to 14 seconds).
- The EDGs will be able to meet the 14 second requirement for output breaker closure when considering a LOCA coincident with a degraded voltage condition (this is determined in calculation 2004-0002 (Reference X.1.01), but will be re-validated here.
- 4.16 kV loads are stripped prior to closing the EDG output breakers to prevent block loading the 4.16 kV loads and allow proper sequencing (see discussion below).
- 480 V loads are stripped prior to closing the EDG output breakers to prevent block loading the 480 V loads and allow proper sequencing (see discussion below).
- The motor voltage for both 4.16 kV and 480 V motor loads has decayed to a safe level prior to re-energizing buses to prevent damage to the motors from being energized out of synchronization with the incoming EDG voltage (see discussion below).

The requirements in the last three bullets are implicitly assumed in the accident analyses in the FSAR (Reference X.8.05) and AC Electrical System Analysis (Reference X.1.01) where load sequencing occurs correctly without damage to equipment.

A rough time line of the sequence of events during a loss of voltage is shown in Figure 10. Note that the time values shown are approximate and are not to scale. They are intended to give a rough feel for the time spans involved in the evolution. They are NOT intended to represent final setpoints or all anticipated system conditions. The voltage decay values shown represent bounding (longest) values. Shorter (but non-zero) decay times will be observed depending upon system loading and alignment.

Section VII – A05/A06 Bus LOV Relay Setting

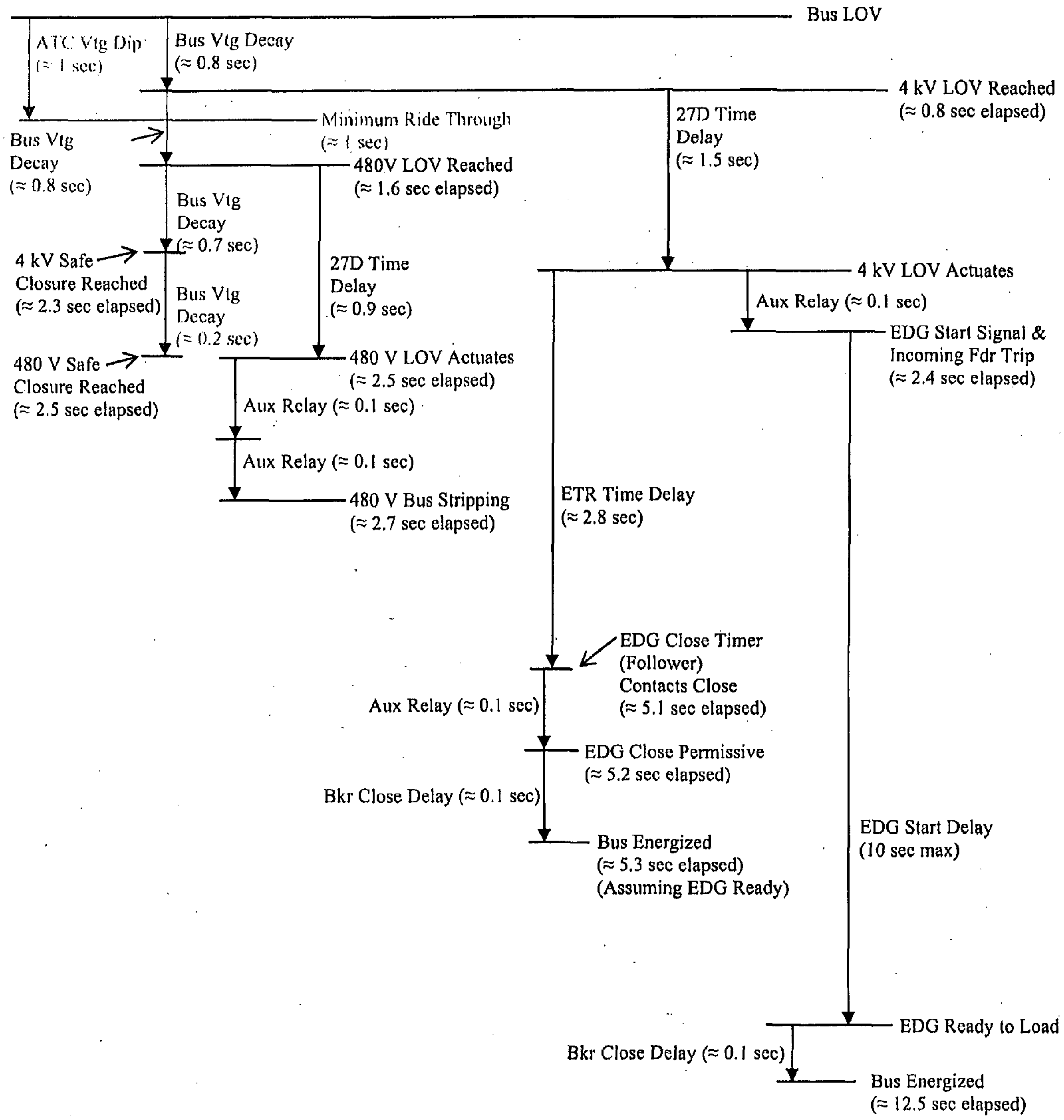


Figure 10

Section VII – A05/A06 Bus LOV Relay Setting

VII.2 METHODOLOGY

The methodology used in this calculation section is not described in the Current Licensing Basis (CLB) for PBNP. The methodology is similar to, but not identical to or dependent upon the methodology that is described in the CLB for determining the time delay settings for the degraded voltage relay time delay settings. The methodology used for the settings is similar to the methodology used for bus A01/A02.

VII.2.01 VOLTAGE SETPOINT METHODOLOGY

A diagram showing the relationship of the values used to determine the voltage element setpoint for an LOV relay is shown in Figure 11:

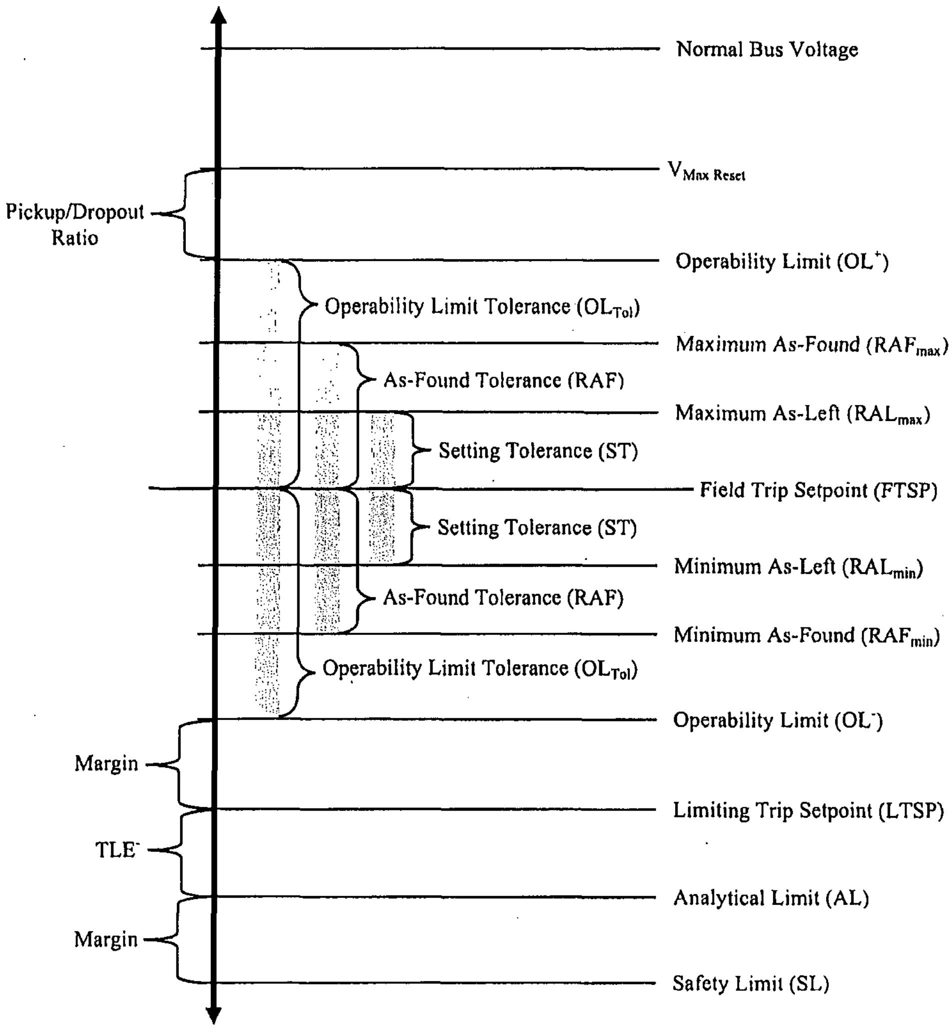


Figure 11

Section VII – A05/A06 Bus LOV Relay Setting

The general approach is to determine the Limiting Trip Setpoint (LTSP) from the Analytical Limit (AL) and Total Loop Error (TLE). Then the difference between the Operability Limit (OL) and Field Trip Setpoint (FTSP) is determined. The FTSP is determined by starting with the LTSP and adding the intentional margin (if any) between the LTSP and OL plus the difference between the OL and the FTSP. In this calculation, the margin is not added intentionally as part of selecting the setpoints. The margin is quantified after determining the setpoints and limits. The remaining limit values are calculated from the FTSP using the cited tolerances. The inputs required are the AL, 2σ drift (d), TLE, Setting Tolerance (ST), and Operability Limit tolerance (OL_{Tol}). The analytical limit comes from reference documents and is generally tied to the CLB. The remaining values are determined in this calculation. The 2σ drift (d), TLE, and a calculated Setting Tolerance (ST) are determined in Section II of this calculation. The final values are tabulated in Section II.7.

The LTSP, FTSP, as-left, as-found, and operability limit values are determined using the methodology previously described in Section IV.2.01.

VII.2.02 TIME DELAY SETPOINT METHODOLOGY

A diagram showing the relationship of the values used to determine the timing setpoint for a time delay element or relay is shown in Figure 12:

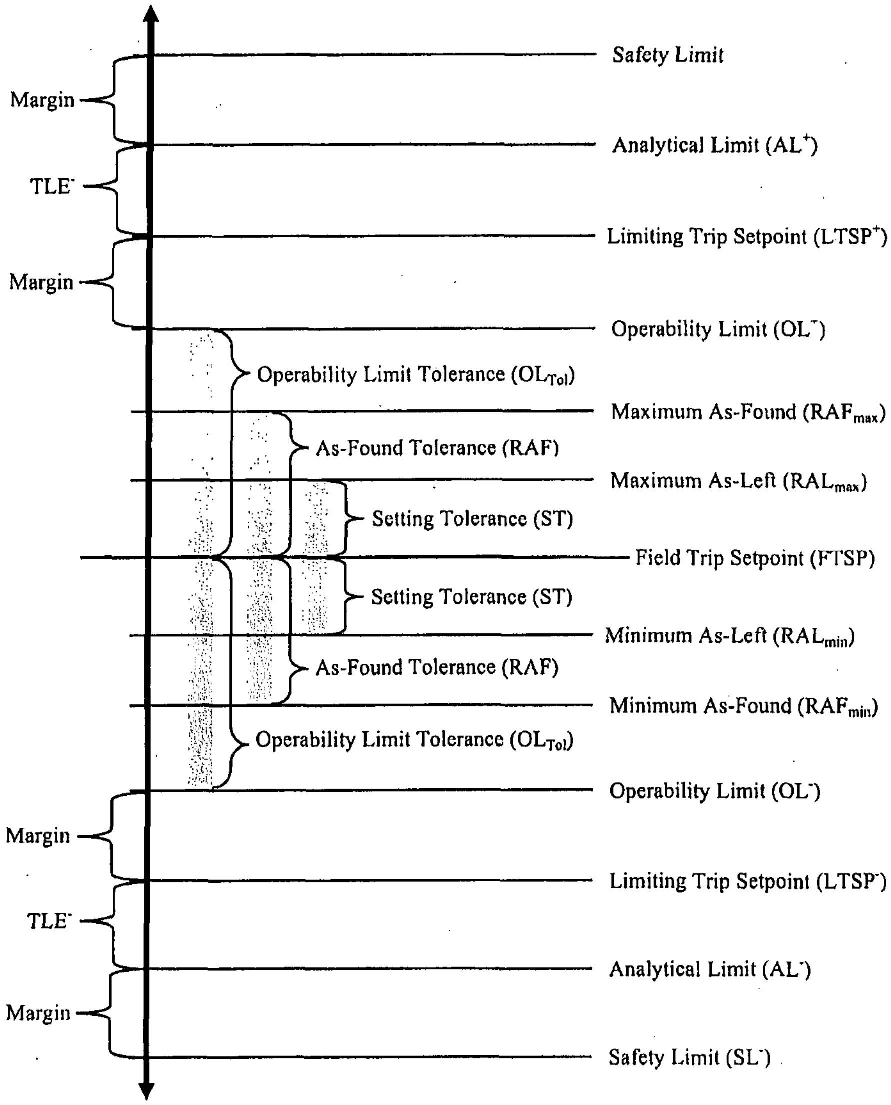


Figure 12

The general approach is to determine the Limiting Trip Setpoint (LTSP) from the Analytical Limits (ALs) and Total Loop Error (TLE). Then the difference between the Operability Limits (OLs) and Field Trip Setpoint (FTSP) is determined. The FTSP is determined by starting with the LTSP and adding the intentional margin (if any) between the LTSP and OL plus the difference between the OL and the FTSP. In this calculation, the margin is not added intentionally as part of selecting the setpoints. The margin is quantified after determining the setpoints and limits. The remaining as-left and as-found limit values are calculated from the FTSP using the cited tolerances as described in Section IV.2.01. The inputs required are the AL, 2σ drift (d), TLE, Setting Tolerance (ST), and Operability Limit tolerance (OL_{Tol}). The analytical limit comes from reference documents and is generally tied to the CLB. The remaining values are determined in this calculation. The 2σ drift (d), TLE, and a calculated Setting Tolerance (ST) are determined in Section II of this calculation. The final values are tabulated in Section II.7.

The LTSP, FTSP, as-left, as-found, and operability limit values are determined using the methodology previously described in Section IV.2.01.

VII.2.03 METHODOLOGY FOR THE LOV RELAY SETTINGS

The technical specification limit for the LOV relay trip settings will be used as the lower operability limit (OL_{min}) for the voltage element. The setting of the time delay element and EDG close timer (follower) TDR will be based on the requirement that the 4.16 kV LOV relays and time delay relays must coordinate with the 480 V LOV relays to ensure that the 4.16 kV safety buses are repowered after the 480 V buses are stripped (Acceptance Criteria VIII.3.04). The following will be considered when establishing the time delay relay setpoints:

- The effect of bus voltage decay time on the 4.16 kV and 480 V LOV relay start times using the most conservative LOV relay voltage and time setting limits.
- Time delays associated with equipment (auxiliary relays, circuit breakers, etc.) which operate in series with the 4.16 kV and 480 V LOV relays to perform safety functions.
- Current licensing basis assumptions for maximum EDG start times.

For voltage settings, the lower bound technical specification allowable value is taken to be equal to the LTSP and the lower operability limit (OL^-). That is, no intentional margin is added at this point in the setpoint determination.

Starting with the lower operability limit, the setpoints, as-left limits, as-found limits, operability limits, and maximum reset voltage will be determined using the methodology described in Section IV.2.01.

For time delay settings, new safety limits, technical specification allowable values and operating limits will be developed since the existing limits will not support the ride through requirements of Reference X.4.12.

VII.3 ACCEPTANCE CRITERIA

VII.3.01 Relays 1(2)-271/A05, 1(2)-272/A05, 1(2)-273/A05, 1(2)-271/A06, 1(2)-272/A06, and 1(2)-273/A06 shall be set to protect the Technical Specifications minimum allowable voltage of 3156 V.

VII.3.02 The voltage at the A05 and A06 buses must remain above the maximum drop-out value (OL^+) for relays 1(2)-271/A05, 1(2)-272/A05, 1(2)-273/A05, 1(2)-271/A06, 1(2)-272/A06, and 1(2)-273/A06 for all anticipated motor starting events. This acceptance criterion is based on an implicit assumption made in Chapter 8 of the FSAR (Reference X.8.05.1).

Section VII – A05/A06 Bus LOV Relay Setting

VII.3.03 The time delay element settings for relays 1(2)-271/A05, 1(2)-272/A05, 1(2)-273/A05, 1(2)-271/A06, 1(2)-272/A06, and 1(2)-273/A06 relays shall be short enough to ensure that the LOV logic actuates and initiates the required actions in time to support the actuation times used in the applicable accident analyses (Reference X.8.05.6).

VII.3.04 The time delay setpoint of the LOV relay logic scheme must be long enough to prevent spurious actuation during transients imposed by offsite power disturbances. To remain within the Transmission System Operator voltage recovery analysis supporting Reference X.4.12, a dual unit trip should not be caused by a single transient disturbance. Therefore, the LOV relays should not prematurely trip upon these disturbances. This acceptance criterion is based on an implicit assumption made in Chapter 8 of the FSAR (Reference X.8.05.1).

VII.3.05 The time delay setpoint of the EDG Close Timer (follower) relay must be long enough to ensure that the safe closure thresholds established in calculation 2005-0007 (Reference X.1.07) are reached before the EDG breaker close permissive occurs.

VII.3.06 The time delay setpoint of the EDG Close Timer (follower) relay must be long enough to ensure that the 4.16 kV stripping is initiated before the EDG breaker close permissive occurs.

VII.3.07 The time delay setpoint of the EDG Close Timer (follower) relay must be short enough to ensure that the EDG breaker close permissive occurs in time to support the actuation times used in the applicable accident analyses (Reference X.8.05.6).

VII.4 ASSUMPTIONS

Validated Assumptions

VII.4.01 It is assumed that the pick up time for all of the auxiliary relays in this LOV scheme is 0.083 seconds.

Basis: There are four types of auxiliary relay in this scheme. Their operating times are given as:

- MG-6 = 0.083 s (Reference X.11.01)
- NBFD65NR = 0.050 s (Reference X.11.01)
- RXMA-2 = 0.010 s (Reference X.11.03)
- RXMH-2 = 0.050 s (Reference X.11.03)

For simplicity and conservatism, all four relay types well are treated as having a pick up time equal to the slowest relay (0.083 s).

VII.4.02 It is assumed that the EDG breaker closing time is 0.090 sec.

Basis: The Routine Maintenance Procedure for the safety related 4.16 kV circuit breakers (Reference X.6.21) uses 0.090 seconds as the maximum allowable closing time for the circuit breakers.

Unvalidated Assumptions

None

VII.7 RESULTS

VII.7.01 VOLTAGE ELEMENT SETTINGS

The voltage element settings for the A05/A06 LOV relays are tabulated below. Values below the FTSP are conservatively rounded up to the nearest 0.01 V. Values above the FTSP except $V_{Max\ Reset}$ are conservatively rounded down to the nearest 0.01 V. The $V_{Max\ Reset}$ value is conservatively rounded up to the next 0.01 V. Values are presented in volts on the relay base, with the voltage on the 4.16 kV bus base in parenthesis for selected values.

As discussed previously, the existing as-left setting range in the RMPs (91.8 V to 92.8 V per Inputs II.5.03.3 and II.5.04.3) supports the technical specifications allowable value. This setting tolerance is effectively an FTSP of 92.3 V with a setting tolerance of ± 0.5 V, or ± 0.541%. The existing FTSP is more conservative than the calculated FTSP.

The voltages for both the calculated settings (based on no additional margin in the calculated settings, that is, setting the LTSP=AV) using the ideal setting tolerance and the existing effective FTSP of 92.3 V and setting tolerance of ±0.541% are tabulated.

			Recommended Setting	
Setting	Value (Calculated Settings)		Value (Existing Effective FTSP & ST)	
$V_{Max\ Reset}$	95.77 V	(3342 V)	96.27 V	(3363 V)
OL_{max}	92.98 V	(3245 V)	93.47 V	(3265 V)
RAF_{max}	92.7 V		93.16 V	
RAL_{max}	92.42 V		92.79 V	
FTSP	91.72 V		92.30 V	
RAL_{min}	91.01 V		91.81 V	
RAF_{min}	90.72 V		91.44 V	
OL_{min}	90.45 V		91.13 V	
TS Allowable	90.443 V	(3156 V)	90.443 V	(3156 V)

Section VII – A05/A06 Bus LOV Relay Setting

As shown in the table above, the existing effective setting of 92.3 V with a setting tolerance of ± 0.541% protects the technical specifications allowable values. The margin between the operability limit and the technical specification allowable value is 0.773 V, or 0.9%. Therefore, Acceptance Criteria VII.3.01 for the voltage element of the A05/A06 LOV relay voltage elements is met with the existing effective FTSP of 92.3 V and effective setting tolerance of ± 0.541%.

The maximum reset voltage is 3363 V. The upper operability limit of the dropout voltage is 3265 V. These are both below the lowest voltage expected at any of the A05/A06 buses during an RCP start (3512 V per Section III.7). It is also below the lowest voltage (3750 V) observed at these buses in the dynamic motor starting analyses (Section III.7.02 of Reference X.1.01). Therefore, acceptance criteria VII.3.02 for the voltage elements of the A05/A06 LOV relays is met with either set of relay settings and limits. The margin from $V_{Max\ Reset}$ to the minimum expected voltage is 3512 V – 3363 V = 149 V, or 4.4%.

VII.7.02 TIME DELAY ELEMENT SETTINGS

The time delay element settings for the A05/A06 LOV relays are tabulated below. Values below the FTSP are conservatively rounded up to the nearest 0.001 s. Values above the FTSP are conservatively rounded down to the nearest 0.001 s.

The existing setting tolerance in the RMPs (Inputs II.5.03.3 and II.5.04.3) for the A05/A06 LOV relay time delay elements is 0.8 s ± 0.4 s, or ± 5%. This setting tolerance is achievable in the field (the relays have been successfully calibrated using the existing RMPs).

As discussed previously, using the new FTSP with the existing as-left setting tolerance in the RMPs (± 5% per Inputs II.5.03.3 and II.5.04.3) supports the technical specifications allowable value.

Section VII – A05/A06 Bus LOV Relay Setting

The times for the calculated FTSP using both the ideal setting tolerance of ± 2.22% and the existing setting tolerance of ± 5% are tabulated. The as-left and operability limits for the existing FTSP and setting tolerance (calculated using the same method as the other tabulated values) are also tabulated.

Setting	Recommended Setting Value (Calculated Settings)	Value (± 5% ST)	Value (Existing Settings)
SL^+	3.0 s	3.0 s	3.0 s
$LTSP_{upper}$	2.835 s	2.835 s	2.835 s
OL_{max}	1.564 s	1.594 s	0.850 s
RAF_{max}	1.551 s	1.586 s	
RAL_{max}	1.533 s	1.575 s	0.840 s
FTSP	1.500 s	1.500 s	0.800 s
RAL_{min}	1.467 s	1.425 s	0.760 s
RAF_{min}	1.453 s	1.418 s	
OL_{min}	1.440 s	1.410 s	0.750 s
$LTSP_{lower}$	1.111 s	1.058 s	1.058 s
SL^-	1.05 s	1.0 s	1.0 s

As shown in the table above, the calculated FTSP of 1.5 s with the existing setting tolerance of ± 5% protects the technical specifications allowable values and safety limits.

At the upper end of the range, the margin between the operability limit and the technical specification allowable value is 1.27 s, or 44.8% using the calculated setting tolerance of ± 2.22%. Using the ± 5% setting tolerance reduces the margin to 1.24 s, or 43.8%. Therefore, Acceptance Criteria VII.3.03 is met for the time delay element of the A05/A06 LOV relay for both setting tolerances.

At the lower end of the range, the margin between the operability limit and the technical specification allowable value is 0.33 s, or 29.6% using the calculated setting tolerance of ± 2.22%. Using the ± 5% setting tolerance reduces the margin to 0.30 s, or 26.9%. Therefore, Acceptance Criteria VII.3.04 is met for the time delay element of the A05/A06 LOV relay for both setting tolerances.

Section VII – A05/A06 Bus LOV Relay Setting

VII.7.03 EDG CLOSE TIMER (FOLLOWER) TIME DELAY RELAY SETTINGS

The time delay element settings for the EDG close timer (follower) time delay relays (1(2)-62-4/A05, 1(2)-62-5/A05, 1(2)-62-4/A06 and 1(2)-62-5/A06) are tabulated below. Values below the FTSP are conservatively rounded up to the nearest 0.001 s. Values above the FTSP are conservatively rounded down to the nearest 0.001 s.

The existing setting tolerance in the RMPs (Inputs II.5.03.3 and II.5.04.3) for the A05/A06 EDG close timer (follower) time delay relay is 3.0 s ± 0.15 s, or ± 5%. This setting tolerance is achievable in the field (the relays have been successfully calibrated using the existing RMPs).

As discussed previously, using the existing FTSP and as-left setting tolerance in the RMPs (± 5% per Inputs II.5.03.3 and II.5.04.3) supports the technical specifications allowable values determined for these relays. The calculated values based on an FTSP of 2.75 s provide additional margin to the 14 s requirement for EDG breaker closure when starting under degraded grid coincident with a LOCA.

The times for both the calculated settings using the ideal FTSP and a setting tolerance of ± 5.085% and the existing FTSP and a setting tolerance of ± 5% are tabulated.

Setting	Recommended Setting Value (Calculated Settings) (FTSP = 2.75 s, ST = 5.085%)	Value (Existing Settings) (FTSP = 3.0 s, ST = 5.0%)
SL^+	4.0 s	4.0 s
$LTSP_{upper}$	3.806 s	3.806 s
OL_{max}	2.999 s	3.270 s
RAF_{max}	2.946 s	3.212 s
RAL_{max}	2.889 s	3.150 s
FTSP	2.750 s	3.000 s
RAL_{min}	2.611 s	2.850 s
RAF_{min}	2.554 s	2.788 s
OL_{min}	2.501 s	2.730 s
$LTSP_{lower}$	1.686 s	1.686 s
SL^-	1.6 s	1.6 s

As shown in the table above, both combinations of FTSP and ST protect the technical specifications allowable values and safety limits determined in this calculation for these relays.

At the upper end of the range, the margin between the operability limit and the technical specification allowable value using the calculated FTSP of 2.75 s ± 5.085% is 0.81 s, or 21.3%. Using the existing FTSP of 3.0 s ± 5% reduces the margin to 0.53 s, or 13.9%. Since both have positive margin, Acceptance Criteria VII.3.05 and VII.3.06 are met for the time delay element of the A05/A06 EDG close timer (follower) time delay relay for both setting ranges.

At the lower end of the range, the margin between the operability limit and the technical specification allowable value using the calculated FTSP of 2.75 s ± 5.085% is 0.82 s, or 48.6%. Using existing FTSP of 3.0 s ± 5% increases the margin to 1.04 s, or 61.7%. Since both have positive margin, Acceptance Criteria VII.3.07 is met for the time delay element of the A05/A06 LOV relay for both setting ranges.

Although the existing FTSP and setting tolerance meet all acceptance criteria, it is recommended that the calculated FTSP and setting tolerance of 2.75 s ± 5.085% be used. The margin to the lower safety limit conservatively ignores the effect of accelerated voltage decay when additional loads are operating on the buses. This provides additional unquantified margin on the lower end of the range. This and the importance of loading the EDGs quickly during a LOCA coincident with a degraded grid condition argue for selecting the shorter delay for these relays.

VII.8 CONCLUSIONS

The existing setting tolerance for the voltage element in the A05/A06 LOV relays (1(2)-271/A05, 1(2)-272/A05, 1(2)-273/A05, and 1(2)-271/A06, 1(2)-272/A06 and 1(2)-273/A06) results in an effective FTSP of 92.3 V with a setting tolerance of ±0.541%. The calculation results show that retaining these values protects the technical specifications allowable value and meets Acceptance Criteria VII.3.01 and VII.3.02 for the voltage element with margin. It is recommended that the existing setting tolerance be retained and that the nominal setpoint in the setpoint documents (STPT 21.1 sheets 39 , 66, 103 and 112) and maintenance procedures (1(2)RMP 9056-1 and 1(2)RMP 9056-2) be revised to reflect the effective nominal FTSP of 92.3 V. Incorporating these changes is tracked under AR 01131460.

The Technical Specifications allowable time of ≥0.7 seconds and ≤1.0 seconds for the 1(2)-271/A05, 1(2)-272/A05, 1(2)-273/A05, and 1(2)-271/A06, 1(2)-272/A06, 1(2)-273/A06 relays are no longer adequate to support the design functions of the relays. The need to ride through a worst case grid fault with a duration of 1 second is required to avoid unnecessary separation from the grid (note that separating the A05/A06 buses does not necessarily cause a plant trip) with its attendant challenge to the safety related equipment (particularly the EDGs). Therefore, a TS change is required. AR 01131451 has been initiated to address this issue.

The calculated settings for the time delay element in the A05/A06 LOV relays result in an FTSP of 1.5 s. Both the calculated setting tolerance of ± 2.22% and the existing setting tolerance of ± 5% protect both the upper and lower technical specification allowable values and safety limits determined in this calculation for these relay elements. It is recommended that the calculated setting tolerance of ± 2.22% be implemented with the new FTSP of 1.5 s to take advantage of the additional margin afforded at both ends of the timing range. Setpoint documents STPT 21.1 STPT 21.1 sheets 39 , 66, 103 and 112 and maintenance procedures 1(2)RMP 9056-1 and 1(2)RMP 9056-2 must be revised to incorporate these changes. Incorporation of these changes is tracked under AR 01131451.

The calculated settings for the A05/A06 LOV EDG close timer (follower) time delay relays results in an FTSP of 2.75 s ± 5.085%. Both the calculated FTSP of 2.75 s ± 5.085% and the existing FTSP of 3.0 s ± 5% protect both the upper and lower technical specification allowable values and safety limits determined for these relays in this calculation. It is recommended that the calculated FTSP of 2.75 s ± 5.085% be implemented to take advantage of the additional margin afforded at the upper end of the timing range. Setpoint documents STPT 21.1 sheets 39, 66, 103 and 112 and maintenance procedures 1(2)RMP 9056-1 and 1(2)RMP 9056-2 must be revised to incorporate these changes. Incorporation of these changes to these documents is tracked under AR 01131461.

It is also recommended that the as-found and operability limits be incorporated into the existing maintenance procedures. Incorporation of these limits in the maintenance procedures are also discussed and tracked in ARs 01131451 and 01131461.

Section VII – A05/A06 Bus LOV Relay Setting

The M&TE accuracy used in determining the relay settings is tabulated below. Alternate M&TE with accuracy equal to or better than that tabulated may be substituted. Alternate M&TE with lower accuracy will require additional analysis. Acceptable alternate M&TE (where known) is identified in the table.

Relay/Element	M&TE Evaluated	Accuracy	Alternate M&TE
ITE-27D/Voltage	Fluke 8505A	± 0.105% of reading	
ITE-27D/Time	Multi-Amp TV-2	± 0.01% of reading	Doble F6150 (± 0.0005% of reading + 50 μsec)
ETR/Time	Fluke 123 Scopemeter	± 0.9% of reading	Doble F6150 (± 0.0005% of reading + 50 μsec)

VIII. B03/ B04 LOV RELAY SETTING

VIII.1 PURPOSE AND SCOPE

The purpose of this calculation section is to determine the dropout voltage and time delay settings for the loss of voltage relaying scheme for 480 V buses 1B03, 1B04, 2B03, and 2B04.

The scope of this calculation section includes settings for the LOV relays. The specific relays whose settings included in the scope of this calculation section are tabulated below:

Function	Relays IDs
LOV	1(2)-271/B03, 1(2)-272/B03, 1(2)-273/B03, 1(2)-271/B04, 1(2)-272/B04, 1(2)-273/B04

A block diagram of the logic scheme evaluated in this section is presented in Figure 13:

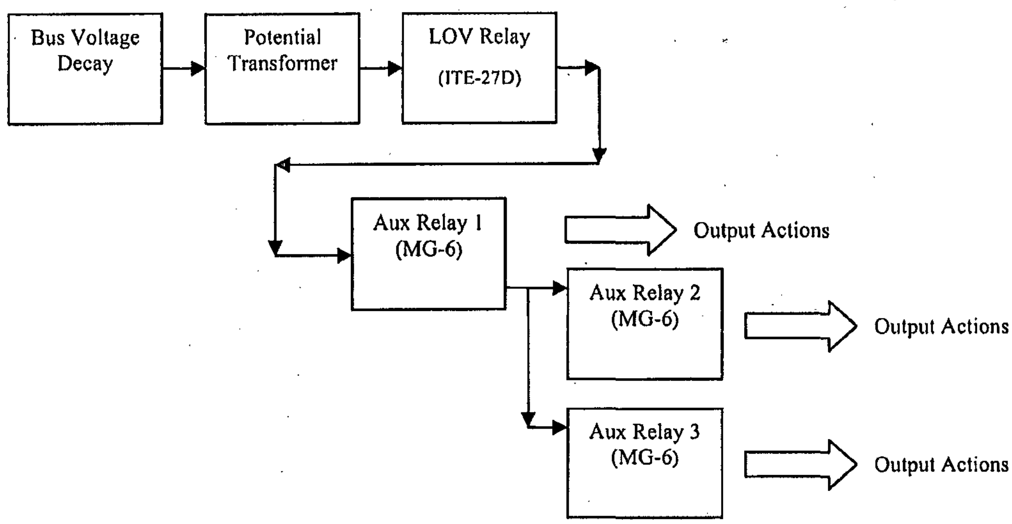


Figure 13

In this scheme, Aux relay 1 initiates an annunciator. Aux relay 2 initiates 480 V bus stripping. Aux relay 3 initiates 480 V bus stripping and load sequence timers (References X.5.30 through X.5.37).

Section VIII – B03/ B04 LOV Relay Setting

The voltage and time delay settings for the relays in this scheme must be selected in conjunction with the voltage and time delay settings for the 4.16 kV LOV relays at buses A05/A06 (Section VII) to ensure the following, whether the EDGs are running prior to the LOV or not:

- The EDGs will be started and their output breakers can be closed onto the bus in 14 seconds or less (The accident analyses in Reference X.8.05.6 assume 15 seconds, but Reference X.1.06 reduces this to 14 seconds).
- The EDGs will be able to meet the 14 second requirement for output breaker closure when considering a LOCA coincident with a degraded voltage condition (this is determined in calculation 2004-0002 (Reference X.1.01), but will be re-validated here.
- 4.16 kV loads are stripped prior to closing the EDG output breakers to prevent block loading the 4.16 kV loads and allow proper sequencing (see discussion below).
- 480 V loads are stripped prior to closing the EDG output breakers to prevent block loading the 480 V loads and allow proper sequencing (see discussion below).
- The motor voltage for both 4.16 kV and 480 V motor loads has decayed to a safe level prior to re-energizing buses to prevent damage to the motors from being energized out of synchronization with the incoming EDG voltage (see discussion below).

The requirements in the last three bullets are implicitly assumed in the accident analyses in the FSAR (Reference X.8.05) and AC Electrical System Analysis (Reference X.1.01) where load sequencing occurs correctly without damage to equipment.

A rough time line of the sequence of events during a loss of voltage is shown in Figure 10 in Section VII. Note that the time values shown in the figure are approximate and are not to scale. They are intended to give a rough feel for the time spans involved in the evolution. They are NOT intended to represent final setpoints or all anticipated system conditions. The voltage decay values shown represent bounding (longest) values. Shorter (but non-zero) decay times will be observed depending upon system loading and alignment.

VIII.2 METHODOLOGY

The methodology used in this calculation section is not described in the Current Licensing Basis (CLB) for PBNP. The methodology is similar to, but not identical to or dependent upon methodology that is described in the CLB for determining the time delay settings for the degraded voltage relay time delay settings. The methodology used for the settings is similar to the methodology used for bus A01/A02.

VIII.2.01 VOLTAGE SETPOINT METHODOLOGY

A diagram showing the relationship of the values used to determine the voltage element setpoint for an LOV relay is shown in Figure 14:

Section VIII – B03/ B04 LOV Relay Setting

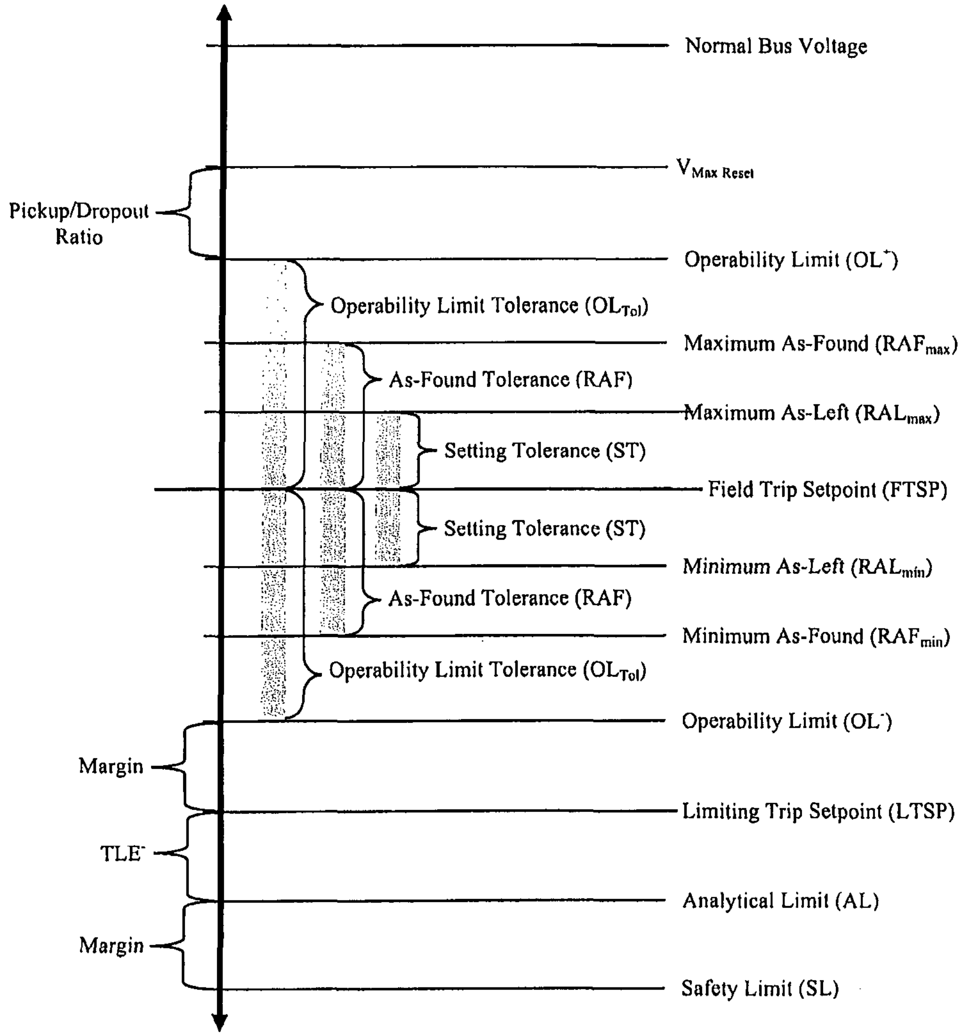


Figure 14

The general approach is to determine the Limiting Trip Setpoint (LTSP) from the Analytical Limit (AL) and Total Loop Error (TLE). Then the difference between the Operability Limit (OL) and Field Trip Setpoint (FTSP) is determined. The FTSP is determined by starting with the LTSP and adding the intentional margin (if any) between the LTSP and OL plus the difference between the OL and the FTSP. In this calculation, the margin is not added intentionally as part of selecting the setpoints. The margin is quantified after determining the setpoints and limits. The remaining limit values are calculated from the FTSP using the cited tolerances. The inputs required are the AL, 2σ drift (d), TLE, Setting Tolerance (ST), and Operability Limit tolerance (OL_{Tol}). The analytical limit comes from reference documents and is generally tied to the CLB. The remaining values are determined in this calculation. The 2σ drift (d), TLE, and a calculated Setting Tolerance (ST) are determined in Section II of this calculation. The final values are tabulated in Section II.7.

Section VIII – B03/ B04 LOV Relay Setting

The LTSP, FTSP, as-left, as-found, and operability limit values are determined using the methodology previously described in Section IV.2.01.

VIII.2.02 Time Delay Setpoint Methodology

A diagram showing the relationship of the values used to determine the timing setpoint for a time delay element or relay is shown in Figure 15:

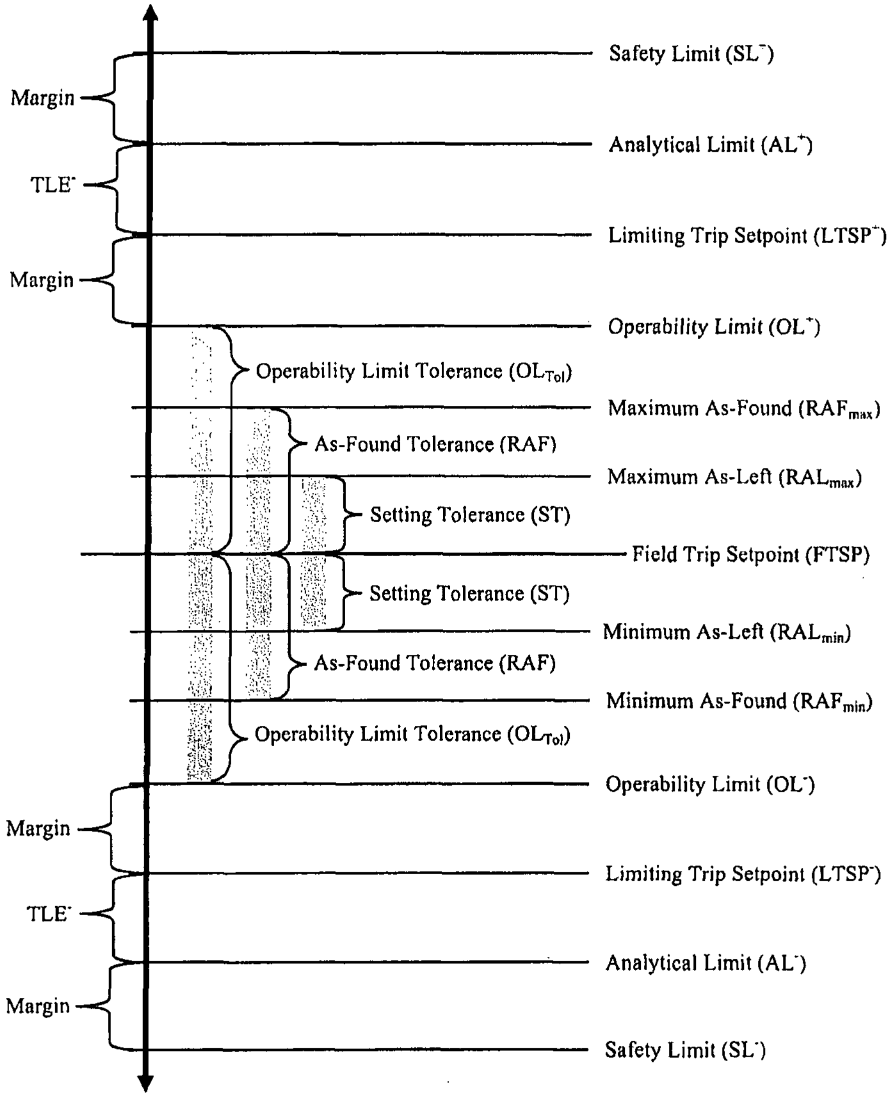


Figure 15

The general approach is to determine the Limiting Trip Setpoint (LTSP) from the Analytical Limits (ALs) and Total Loop Error (TLE). Then the difference between the Operability Limits (OLs) and Field Trip Setpoint (FTSP) is determined. The FTSP is determined by starting with the LTSP and adding the intentional margin (if any) between the LTSP and OL plus the difference between the OL and the FTSP. In this calculation, the margin is not added intentionally as part of selecting the setpoints. *The margin is quantified after determining the setpoints and limits.* The remaining as-left and as-found limit values are calculated from the FTSP using the cited tolerances as described in Section IV.2.01. The inputs required are the AL, 2σ drift (d), TLE, Setting Tolerance (ST), and Operability Limit tolerance (OL_{Tol}). The analytical limit comes from reference documents and is generally tied to the CLB. The remaining values are determined in this calculation. The 2σ drift (d), TLE, and a calculated Setting Tolerance (ST) are determined in Section II of this calculation. The final values are tabulated in Section II.7.

The LTSP, FTSP, as-left, as-found, and operability limit values are determined using the methodology previously described in Section IV.2.01.

VIII.2.03 METHODOLOGY FOR THE LOV RELAY SETTINGS

The technical specification limit for the LOV relay trip settings will be used as the lower operability limit (OL_{min}) for the voltage element. The setting of the time delay element and EDG close timer (follower) TDR will be based on the requirement that the 4.16 kV LOV relays and time delay relays must coordinate with the 480 V LOV relays to ensure that the 4.16 kV safety buses are repowered after the 480 V buses are stripped (Acceptance Criteria VIII.3.04). The following will be considered when establishing the time delay relay setpoints:

- The effect of bus voltage decay time on the 4.16 kV and 480 V LOV relay start times using the most conservative LOV relay voltage and time setting limits.
- Time delays associated with equipment (auxiliary relays, circuit breakers, etc.) which operate in series with the 4.16 kV and 480 V LOV relays to perform safety functions.
- Current licensing basis assumptions for maximum EDG start times.

For voltage settings, the lower bound technical specification allowable value is taken to be equal to the LTSP and the lower operability limit (OL^-). That is, no intentional margin is added at this point in the setpoint determination.

Starting with the lower operability limit, the setpoints, as-left limits, as-found limits, operability limits, and maximum reset voltage will be determined using the methodology described in Section IV.2.01.

For time delay settings, new safety limits, technical specification allowable values and operating limits will be developed since the existing limits will not support the ride through ride through requirements of Reference X.4.12.

Section VIII – B03/ B04 LOV Relay Setting

VIII.3 ACCEPTANCE CRITERIA

VIII.3.01 1(2)-271/B03, 1(2)-272/B03, 1(2)-273/B03, and 1(2)-271/B04, 1(2)-272/B04, 1(2)-273/B04 relays shall be set to protect the Technical Specifications minimum allowable voltage of 256±3% V.

VIII.3.02 The voltage at the B03 and B04 buses must remain above the maximum drop-out value (OL^+) for relays 1(2)-271/B03, 1(2)-272/B03, 1(2)-273/B03, and 1(2)-271/B04, 1(2)-272/B04, 1(2)-273/B04 for all anticipated motor starting events. This acceptance criterion is based on an implicit assumption made in Chapter 8 of the FSAR (Reference X.8.05.1).

VIII.3.03 The time delay element settings for relays 1(2)-271/B03, 1(2)-272/B03, 1(2)-273/B03, and 1(2)-271/B04, 1(2)-272/B04, 1(2)-273/B04 relays must be short enough to ensure that the LOV logic actuates and initiates the required actions in time to support the actuation times used in the applicable accident analyses (Reference X.8.05.6).

VIII.3.04 The time delay element settings for relays 1(2)-271/B03, 1(2)-272/B03, 1(2)-273/B03, and 1(2)-271/B04, 1(2)-272/B04, 1(2)-273/B04 relays must be short enough to ensure that the 480 V stripping is initiated before the EDG breaker close permissive occurs.

VIII.3.05 The time delay element settings for relays 1(2)-271/B03, 1(2)-272/B03, 1(2)-273/B03, and 1(2)-271/B04, 1(2)-272/B04, 1(2)-273/B04 must be long enough to prevent spurious actuation during transients imposed by offsite power disturbances. To remain within the Transmission System Operator voltage recovery analysis supporting Reference X.4.12, a dual unit trip should not be caused by a single transient disturbance. Therefore, the LOV relays should not prematurely trip upon these disturbances. This acceptance criterion is based on an implicit assumption made in Chapter 8 of the FSAR (Reference X.8.05.1).

VIII.4 ASSUMPTIONS

Validated Assumptions

VIII.4.01 It is assumed that the EDG breaker closing time is 0.090 sec.

Basis: The Routine Maintenance Procedure for the safety related 4.16 kV circuit breakers (Reference X.6.21) uses 0.090 seconds as the maximum allowable closing time for the circuit breakers.

Unvalidated Assumptions

None

Section VIII – B03/ B04 LOV Relay Setting

VIII.7 RESULTS

VIII.7.01 VOLTAGE ELEMENT SETTINGS

The voltage element settings for the B03/B04 LOV relays are tabulated below. Values below the FTSP are conservatively rounded up to the nearest 0.01 V. Values above the FTSP except $V_{Max\ Reset}$ are conservatively rounded down to the nearest 0.01 V. The $V_{Max\ Reset}$ value is conservatively rounded up to the next 0.01 V. Values are presented in volts on the relay base, with the voltage on the 480 V bus base in parenthesis for selected values.

As discussed previously, the existing as-left setting range in the RMPs (63.26 V – 64.26 V per Input II.5.05.3) supports the technical specifications allowable value. This setting tolerance is effectively an FTSP of 63.76 V with a setting tolerance of ± 0.5 V, or ± 0.784%. The existing FTSP is more conservative than the calculated FTSP.

The voltages for both the calculated settings using the ideal setting tolerance of ±0.830% and the existing effective FTSP of 63.76 V and setting tolerance of ±0.784% are tabulated.

			Recommended Setting	
Setting	Value (Calculated Settings)		Value (Existing Effective FTSP & ST)	
$V_{Max\ Reset}$	65.582 V	(263 V)	66.41 V	(266 V)
OL_{max}	63.67 V	(255 V)	64.48 V	(259 V)
RAF_{max}	63.59 V		64.40 V	
RAL_{max}	63.46 V		64.26 V	
FTSP	62.94 V		63.76 V	
RAL_{min}	62.42 V		63.26 V	
RAF_{min}	62.35 V		63.19 V	
OL_{min}	62.27 V		63.11 V	
TS Allowable	62.267 V	(248.3 V)	62.267 V	(248.3 V)

As shown in the table above, the existing effective setting of 63.76 V with a setting tolerance of ± 0.748% protects the technical specifications allowable values. The margin between the operability limit and the technical specification allowable value increases to 0.84 V, or 1.3%. Therefore, Acceptance Criteria VIII.3.01 for the voltage element of the B03/B04 LOV relay voltage elements is met with either set of relay settings and limits.

The maximum reset voltage is 266 V. The upper operability limit of the dropout voltage is 259 V. These are both below the lowest voltage expected at any of the B03/B04 buses during an RCP start (384 V per Section III.7). It is also below the

Section VIII – B03/ B04 LOV Relay Setting

lowest voltage (380 V) observed at these buses in the dynamic motor starting analyses (Section III.7.02 of Reference X.1.01). Therefore, acceptance criteria VIII.3.02 for the voltage elements of the RCP LOV relays is met with either set of relay settings and limits. Using the existing FTSP and ST, the margin from $V_{Max\ Reset}$ to the minimum expected voltage is 380 V – 266 V = 114 V, or 42.9%.

VIII.7.02 TIME DELAY ELEMENT SETTINGS

The time delay element settings for the B03/B04 LOV relays are tabulated below. Values below the FTSP are conservatively rounded up to the nearest 0.001 s. Values above the FTSP are conservatively rounded down to the nearest 0.001 s. The as-left and operability limits for the existing FTSP and setting tolerance (calculated using the same method as the other tabulated values) are also tabulated.

	Recommended Setting	
Setting	Value (Calculated Settings)	Value (Existing Settings)
SL^+	1.6 s	1.6 s
$LTSP_{upper}$	1.508 s	1.508 s
OL_{max}	0.890 s	0.442 s
RAF_{max}	0.882 s	
RAL_{max}	0.869 s	0.440 s
FTSP	0.850 s	0.400 s
RAL_{min}	0.831 s	0.360 s
RAF_{min}	0.823 s	
OL_{min}	0.815 s	0.358 s
$LTSP_{lower}$	0.440 s	0.440 s
SL^-	0.415 s	0.415 s

As shown in the table above, the calculated FTSP of 0.85 s with the calculated setting tolerance of ± 2.309% protects the technical specifications allowable values and safety limits.

At the upper end of the range, the margin between the operability limit and the technical specification allowable value is 0.62 s, or 41.1%. Therefore, Acceptance Criteria VIII.3.03 and VIII.3.04 are met for the time delay element of the B03/B04 LOV relays.

At the lower end of the range, the margin between the operability limit and the technical specification allowable value is 0.37 s, or 84.2%. Therefore, Acceptance Criteria VIII.3.05 is met for the time delay element of the B03/B04 LOV relays.

Section VIII – B03/ B04 LOV Relay Setting

VIII.8 CONCLUSIONS

The existing setting tolerance for the voltage element in the B03/B04 LOV relays results in an effective FTSP of 63.76 V with a setting tolerance of ±0.784%. The calculation results show that retaining these values protects the technical specifications allowable value and meet Acceptance Criteria VIII.3.01 for the voltage element with margin. It is recommended that the existing setting tolerance be retained and that the nominal setpoint in the setpoint documents (STPT 21.1 sheets 84 through 87) and maintenance procedures (1(2)RMP 9056-4 and 1(2)RMP 9056-5) be revised to reflect the effective nominal FTSP of 63.27 V. Incorporating these changes is tracked under AR 01131460.

The Technical Specifications allowable time of ≤0.5 seconds for the 1(2)-271/B03, 1(2)-272/B03, 1(2)-273/B03, 1(2)-271/B04, 1(2)-272/B04, 1(2)-273/B04 relays is no longer adequate to support the design function of the relays. The ability to ride through a worst case grid fault with a duration of approximately 0.415 second is required to avoid unnecessary separation from the plant distribution system (note that separating the B03/B04 buses does not necessarily cause a plant trip) with its attendant challenge to the safety related equipment. When setting tolerance and drift are considered, 0.5 sec is no longer sufficient to ensure the ride through requirement is met. Therefore, a TS change is required. AR 01131451 has been initiated to address this issue.

The calculated settings for the time delay element in the B03/B04 LOV relays results in an FTSP of 0.85 s. The calculated setting tolerance of ± 2.309% protects both the upper and lower technical specification allowable values and safety limits determined in this calculation for these relay elements. It is recommended that the calculated setting tolerance of ± 2.309% be implemented with the new FTSP of 0.85 s to address the need to ride through a grid fault of 0.415 second duration. Setpoint documents STPT 21.1 sheets 84 through 87 and maintenance procedures 1(2)RMP 9056-4 and 1(2)RMP 9056-5 must be revised to incorporate these changes. Incorporation of these changes is tracked under AR 01131451.

It is also recommended that the as-found and operability limits be incorporated into the existing maintenance procedures. Incorporation of these limits in the maintenance procedures is also discussed and tracked in AR 01131451.

Section VIII – B03/ B04 LOV Relay Setting

The M&TE accuracy used in determining the relay settings is tabulated below. Alternate M&TE with accuracy equal to or better than that tabulated may be substituted. Alternate M&TE with lower accuracy will require additional analysis. Acceptable alternate M&TE (where known) is identified in the table.

Relay/Element	M&TE Evaluated	Accuracy	Alternate M&TE
ITE-27D/Voltage	Fluke 8505A	± 0.105% of reading	
ITE-27D/Time	Multi-Amp TV-2	± 0.01% of reading	Doble F6150 (± 0.0005% of reading + 50 μsec)
ETR/Time	Fluke 123 Scopemeter	± 0.9% of reading	Doble F6150 (± 0.0005% of reading + 50 μsec)

7.0 ANALYSIS

7.1 Since the methodology in revision 0 of this calculation is used to determine the impact of time delay setting changes for the LOV relays for buses A05 / A06 and B03 / B04 and the EDG close timer (follower) relays, the original pages of the calculation sections VII and VIII are marked up to delineate the required changes and analysis. Attachment A contains the changes / analysis for the LOV relay time delay for buses A05 / A06 as well as the ETR relay and Attachment B contains the changes / analysis for the LOV relay time delay for buses B03 / B04.

The allowable time delay ranges for the Technical Specifications for the 4160V and 480V LOV and ETR time delay relays must support the Acceptance Criteria (AC) in Section 3.0.

A. Acceptance Criterion 3.2 requires the ride through delay for the 4.16 kV buses (A05/A06) and 480 V buses (B03/B04) be revised to 1.4 seconds and 1.0 seconds, respectively.

This AC is satisfied by increasing the lower safety limits of the time delays for the 4.16 kV and 480 V LOV relays. The 4.16 kV LOV relay safety limit has been conservatively increased to 1.5 seconds and the 480 V LOV relay safety limit has been increased to 1.0 seconds.

B. Acceptance Criteria 3.1 and 3.6 require that the time delays must allow the EDG output breakers to close within 14 seconds or less to support accident analyses.

These ACs are satisfied since the allowable time delay for the 4.16kV 27D relay has a maximum value of 2.3 seconds. This maximum time delay value is selected as a value between OL_{max} (2.086 sec) and $LTSP_{upper}$ (2.837 sec) as indicated on Attachment A, page 14. Selecting this maximum time delay value of 2.3 sec for the technical specification allows reasonable margin from the maximum operating limit. The elapsed time from Attachment A, pg 2, Fig 10, for the bus to be energized is the sum of the bus voltage decay (0.8 sec), 27D time delay (high allowable Tech Spec range, 2.3 sec), aux relay (0.1 sec), EDG start delay (10 sec) and EDG breaker close delay (0.1 sec). These values total to 13.3 seconds which satisfy the maximum 14 second requirement.

C. Acceptance Criterion 3.5 requires that the 4.16kV loads are stripped prior to closing the EDG output breakers to prevent block loading the 4.16kV loads.

This AC is satisfied since the 4.16kV LOV relay strips the bus at the same time that the ETR time delay starts. Starting the EDG and breaker closure (10.2 sec) after the LOV relay actuates allows sufficient time for the 4.16kV bus to be stripped of loads.

D. Acceptance Criterion 3.3 requires that the 480V loads are stripped prior to closing the EDG output breakers to prevent block loading the 480V loads.

This AC is satisfied by coordination of the 480V LOV time delay and ETR time delay to ensure that the 480V loads are stripped before the ETR relay provides a permissive to close the EDG breaker. The minimum time for the EDG close permissive through the ETR relay is the sum of voltage decay (0.8 sec), 4.16kV LOV minimum allowable time delay (1.8 sec), and ETR minimum allowable time delay (1.95 sec) which totals to 4.55 seconds. The maximum time for the 480V loads to be stripped through the 480V LOV relay is the sum of voltage decay (0.8 sec), voltage decay (0.8 sec), 480V LOV maximum allowable time delay (1.60 sec) and two auxiliary relay actuations (0.2 sec) which totals 3.4 seconds. With the 480V loads stripped a minimum of 1.15 seconds before the EDG breaker close permissive, there is adequate coordination between the 480V LOV relay time delay and the ETR relay time delay.

E. Acceptance Criterion 3.4 requires that the motor voltage for both the 4.16kV and 480V motor loads should be allowed to decay to a safe level prior to re-energizing the buses to prevent damage to the motors.

This AC is satisfied by considering the safe closure time for the 4.16kV and 480V motors. These safe closure times are identified as Input VII.5.04 of reference 5.2. This input identifies the safe closure times for the 4.16kV and 480V motors using the LOV reach (LOV detected) at the 4.16kV buses as the starting time as 2.3 and 2.53 seconds respectively. The quickest time that the EDG breaker can close and energize the buses is through the ETR time delay relay and assumes that the EDG is already running when the 4.16kV LOV is reached. The 4.16kV LOV minimum allowable time delay (1.8 sec) and the ETR minimum allowable time delay (1.95 sec) provides a minimum time of 3.75 seconds of delay between 4.16kV LOV reached and EDG close permissive which is greater than the safe closure time of 2.53 seconds.

7.2 Minor revision A introduces a short term temperature under accident conditions but indicates that the relays actuate early in the accident before the temperature rise. It also concludes that the input and output data of this calculation remains unchanged. Therefore, minor revision A does not impact the input, analyses or conclusion of this minor revision.

8.0 CONCLUSIONS

The conclusions of the base calculation are affected by this minor revision.

The impact of the longer durations of the ride through times due to the transients of the offsite power supply require changes to the time delay settings for each of the LOV relays for buses A05 / A06, B03 / B04 and the EDG close timer (follower relay). The new settings prevent spurious actuation resulting in separation of these buses from the preferred offsite power supply. The relay settings support the actuation times used in the applicable accident analyses. Time delay settings for the EDG close timer meet the criteria for being long enough to ensure that safe closure thresholds are reached and for 4.16 kV stripping is initiated before the EDG breaker close permissive occurs while being short enough to ensure that the EDG breaker close permissive occurs in time to support actuation times used in the applicable accident analyses.

The analysis provided above and Attachment A and B demonstrates that the revised time delays for LOV relays are adequate for the safety related buses, 1/2 - A05/06 and the 1/2 - B03/04, of 2.0 seconds and 1.5 seconds, respectively, based on minimum required time delays 1.4 seconds and 1.0 seconds for the 4160 V and 480 V buses. This minor revision confirms and supports the following time delay changes to Surveillance Requirements (SR) 3.3.4.3.

SR 3.3.4.3 Allowable Time Delay Values for 4.16 kV and 480 V LOV:

- 4.16 kV loss of voltage time delay of ≥1.8 seconds and ≤ 2.3 seconds.
- 480 V loss of voltage time delay of ≥ 1.15 seconds and ≤ 1.6 seconds.

SR 3.3.4.3 Allowable Time Delay Values for DG close timer:

- DG Close Timer (Follower) Allowable Time Delay Allowable Values of ≥ 1.95 seconds and ≤ 3.55 seconds.

SR 3.3.4.3 Allowable Values for 4.16 kV degraded voltage remains unchanged.

ENCLOSURE 7

NEXTERA ENERGY POINT BEACH, LLC
POINT BEACH NUCLEAR PLANT, UNITS 1 AND 2

LICENSE AMENDMENT REQUEST 261
EXTENDED POWER UPRATE
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION

ADDITIONAL INFORMATION - QUESTION 6 RESPONSE
EDG TRANSIENT ANALYSIS WITH AFW AND AST MODIFICATIONS

49 pages follow

I. GENERAL PURPOSE

I.1 PURPOSE

The overall purpose of this calculation is to develop the dynamic motor impedance models for the safety related switchgear motors, develop an AC electrical distribution system model for transient analysis and to perform transient analysis on the safety related AC electrical system that support the design and licensing basis of Point Beach Nuclear Plant and will utilize ETAP to perform part of or all of the analysis. The following transient analyses included in this calculation are the EDG Transient Loading Analysis and the Voltage Decay Analysis.

EDG transient loading analysis is performed to demonstrate the emergency diesel generators (EDGs) are capable of sequentially starting the automatic safety related loads, demonstrate motors start and accelerate their driven equipment within sufficient time to support their specified safety function, and demonstrate protective devices will not prematurely trip. The calculation will evaluate the impact of the 480V loss of voltage (LOV) relays and 480V MCC contactor voltage requirements versus the voltage profile at the 480V Switchgear and MCCs during the load sequence. The capability of the EDG to restart the loads (if the 480V LOV or 480MCC contactors drop out) will be evaluated. The total duration of time the individual safety related loads will be without power will be identified.

Voltage Decay analysis is performed to determine the worst-case time for the stored energy in induction motors fed from the safety related 4160V and 480V switchgear buses to decay to a safe level for an unsynchronized transfer to the Emergency Diesel Generators (EDGs) following a trip of the 4160V switchgear bus supply breaker from offsite power. The trip of the supply breaker may result from a degraded voltage, loss of voltage, spurious breaker opening or etc. Additionally, it's performed to establish the time delay requirements for the loss of voltage scheme (4.16kV loss of voltage (LOV) relays, 480V LOV relays, and the EDG breaker close delay relay) which initiates a permissive for EDG breaker closure following a trip of the supply breaker.

1.0 PURPOSE

The purpose of this engineering evaluation it to evaluate the impact of the new AFW modification design and Alternate Source Term (AST) modifications on the EDG transient analysis performed in Calculation 2005-0007 "Electrical System Transient Analysis". Revision 0 of Calculation 2005-0007 was performed based on the original design of the AFW modification when the AFW motor driven pumps would remain shared between both Unit 1 and Unit 2 with the motors relocated to the 4160V buses. Since completion of Revision 0 of Calculation 2005-0007, the AFW modification design has been changed to Unitize the AFW system where each unit will have one Terry Turbine AFW pump and one Motor Driven AFW pump. The Motor Driven AFW pumps will still be powered from the 4160V bus but the operation of the AFW pump motors has changed from the previously analyzed cases in Calculation 2005-0007 (Ref. 6.2). In addition, the AST modifications will make the control room ventilation fans automatically load onto the EDGs to support accidents from a radiological perspective to maintain control room doses within required limits (Ref. 6.6).

This engineering evaluation is determining the impact on the EDG performance and capability after the new AFW modification and AST modifications have been installed.

2.0 SCOPE

The scope of this engineering evaluation is limited to the impact of the AFW modification and AST modification, as listed below, on Calculation 2005-0007 revision 0. The engineering evaluation will include the following items within the scope: (a) Revise ETAP transient model for modifications listed below (Section II of Calculation 2005-0007), (b) Develop new worst-case loading sequence based on modifications listed below (Section IV.2.04 and IV.2.05 of Calculation 2005-0007), (c) Perform EDG Transient analysis to evaluate worst-case conditions (Section IV.2.06 of Calculation 2005-0007), (d) Evaluation impact of 480V Loss of Voltage Relays (Section IV.2.09 of Calculation 2005-0007), (e) Evaluate motor acceleration times to support meeting Acceptance Criteria IV.3.04 of Calculation 2005-0007, and (f) Evaluate the results of the transient response of the EDG to demonstrate EDGs and motors are capable of starting and accelerating (Section IV.2.06 of Calculation 2005-0007).

<u>AFW Modification</u>: The scope of the AFW Modification based on Reference 6.2

1. Installation of new Motor Driven AFW pump 1P-53 and will be supplied from bus 1A-06 via breaker 1A52-83.
2. Installation of new Motor Driven AFW pump 2P-53 and will be supplied from bus 2A-05 via breaker 2A52-68.
3. The new Motor Driven AFW pumps (1P-53 and 2P-53) are going to be unitized and will only support operation related to its associated Unit. 1P-53 will support Unit 1 and 2P-53 will support Unit 2.
4. The operation of the new Motor Driven AFW pump are utilized to support a design basis accident and will automatically start on the following signals (a) low-low water level in either steam generator in associated unit, (b) loss of both 4.16kV busses supplying the main feedwater pumps for associated unit, (c) ATWS Mitigation System Activation Signal on associated unit, or (d) safety injection signal on associated unit.
5. New AFW MOV 1AF-04067 and 2AF-04067 will be installed to serve as the safety related service water supply to the new Motor Driven AFW pump suction. These valves will receive signals to open on low CST level or low motor driven AFW pump suction pressure in conjunction with a signal that automatically started the pumps. The valves would not receive a signal to open during first 2 minutes of an event which would impact the EDG Transient Analysis.
6. The existing shared Motor Drive AFW pumps (P-38A and P-38B) will remain but will be reclassified as Standby Steam Generator (SSG) pumps. The SSG pumps will be controlled manually for startup, shutdown and certain non-accident events. The SSG pumps control scheme will be modified to remove all automatic controls. Therefore, the SSG pumps will not be automatically loaded onto the EDGs. The SSG pumps control scheme will be modified to trip the SSG pumps upon an AFW initiation signal or EDG safeguards sequence signal.
7. The existing AFW MOVs (AF-04020, AF-04021, AF-04022, and AF-04023) will still support operation of the SSG pumps. These valves will have their control schemes modified to remove the automatic signal to open to support AFW since the SSG pumps will only be operated manually.

<u>AST Modifications</u>: The scope of the AST Modification is based on Reference 6.6

1. The control room ventilation fans (W-013B1, W-013B2, W-014A, and W-014B) control scheme is modified to auto-start on the EDGs upon receipt of a Containment Isolation signal or High Radiation signal.
2. The Façade Freeze Transformer (X-17B) control scheme is modified to de-energize the circuit after a loss of offsite power. Therefore, the Façade Freeze Transformer would <u>not</u> be loaded automatically on to the EDG and plant operators would use the EDG load management procedures to determined when it is acceptable to manually re-energize the load

Section II – Motor Dynamic Impedance Models

II. MOTOR DYNAMIC IMPEDNACE MODELS

II.1 PURPOSE AND SCOPE

II.1.01 PURPOSE:

The purpose of this calculation is to develop a motor impedance model of induction motors supplied by the safety related switchgear. The motor impedance model is developed to dynamically model the motors to perform transient analyses in ETAP. The calculation will determine a composite motor characteristic for each motor service (safety injection (SI), service water (SW), etc.) powered from the safety related switchgear to be dynamically started. The composite motor characteristic envelops the characteristics of the individual motors with a bounding model for each motor service to allow flexibility in replacing motors with its designated spare without impacting this calculation.

II.1.02 SCOPE:

The scope of this calculation is to develop the motor impedance model for the motors required to be dynamically modeled for the EDG transient loading analysis and the voltage decay analysis. The following motors will be modeled in this calculation:

- Safety Injection Pump (SI) Motors
- Component Cooling Water Pump (CCW) Motors
- Service Water Pump (SW) Motors
- Residual Heat Removal Pump (RHR) Motors
- Containment Spray Pump (CS) Motors
- Containment Accident Fan (CAF) Motors

The motor impedance models are developed based on the various individual unique motor characteristics provided by the motor vendor. The composite motor is developed to envelop the characteristics of the individual motors in a service with a bounding motor model for each motor service.

Section II – Motor Dynamic Impedance Models

II.2 METHODOLOGY

The following steps are performed to develop the motor impedance model for each service of motor; namely:

1. Development of input data required to develop the composite motor model.
2. Development of composite motor curves for torque versus speed, current versus speed, and power factor versus speed.
3. Development of a composite nameplate for each motor service.
4. Determine the motor model type (Single 2, Double 1, or Double 2) and develop the impedance model to closely replicate the composite motor curves.
5. Verify the motor impedance model using ETAP (Reference VI.3.01).

II.3 ACCEPTANCE CRITERIA

The following acceptance criteria are being established to ensure the safety related motors dynamic models will represent the installed motors. The motor impedance models to be utilized within transient analyses must demonstrate that the motors connected to the electrical distribution system are capable of performing their required safety and safety support functions as described in the FSAR and to meet PBNP GDC 39 (Reference VI.8.01, VI.8.02, VI.8.03, and VI.8.04). Therefore, the motor torque, motor current, and motor power factor versus speed calculated based on the developed motor impedance models will be compared to the motor vendor data for each service of motors. The following acceptance criteria are established for each service of motor to ensure that the motors are adequately modeled:

II.3.01 The acceleration time of the impedance model must match the vendor data with a small positive tolerance allowed.

II.3.02 The torque versus speed curve of the impedance model must match the vendor data with a small tolerance allowed.

II.3.03 The current versus speed curves of the impedance model must match the vendor data with a small tolerance allowed.

II.3.04 The power factor versus speed curve of the impedance model must match the vendor data with a small tolerance allowed.

II.3.05 The open circuit time constant of the impedance model must match the vendor data with a small positive tolerance allowed.

Section II – Motor Dynamic Impedance Models

II.4 ASSUMPTIONS

II.4.01 VALIDATED ASSUMPTIONS

II.4.01.1 It is assumed the load speed vs. torque for compressors, fans and pumps are as follows:

Fan Load Speed vs. Torque Curve	
Percent of Full Load Speed	Percent of Full Load Torque
0%	20%
5%	11%
10%	2%
15%	4%
20%	5%
25%	7%
30%	9%
35%	13%
40%	17%
45%	21%
50%	26%
55%	32%
60%	38%
65%	45%
70%	52%
75%	60%
80%	67%
85%	76%
90%	85%
92.5%	90%
95%	95%
97.5%	100%

Pump Load Speed vs. Torque Curve	
Percent of Full Load Speed	Percent of Full Load Torque
0%	15%
5%	8%
10%	5%
15%	3%
20%	4%
25%	7%
30%	9%
35%	13%
40%	17%
45%	21%
50%	26%
55%	31%
60%	37%
65%	44%
70%	50%
75%	58%
80%	66%
85%	75%
90%	83%
92.5%	88%
95%	93%
97.5%	97%
98.4%	100%

Basis: The load dynamic characteristics (Speed vs. Torque curves) for centrifugal pumps and fans have a characteristic that torque varies as the square of the speed (Reference VI.2.07 and VI.2.08). The pump speed vs. torque characteristics were established by establishing the worst-case speed vs. torque based on the known pump characteristics provide for the switchgear loads. The fan speed vs. torque characteristics were established based on the typical curve based on reference VI.4.08 and VI.2.08 based on the characteristic that torque varies as the square of speed. The torque at zero speed would theoretically be zero, but the motor must overcome stuffing box friction, rotating element inertia, and bearing friction in order to start the shaft turning. This requires a torque at zero speed that may range from 2.5% to 15% of rated full load torque for pumps (Reference VI.2.07) and from 2.5% to 20% of rated full load torque for fans (Reference VI.2.08 and VI.4.08). Therefore, the torque at

Section II – Motor Dynamic Impedance Models

zero speed was conservatively chosen to be 15% for pumps and 20% for fans of rated full load torque. This provides a single worst-case characteristic for all pumps and fans. The 100% speed and 100% torque was corrected to a slip of 1.6% for pumps and 2.2% for fans based on the worst-case rated load RPM for pumps and fans powered by the switchgear (Reference VI.4.08).

II.4.02 UNVALIDATED ASSUMPTIONS

None

II.7 RESULTS

The impedance models of the motors for each service have been completed and verified. Attachments B5 and B6 contain the output of the MathCAD engine and user interface for each service of motors. Attachment B2 contains the Excel spreadsheets for the unique motor data of torque, current and power factor versus speed used to develop the composite motor curves for each service of motors. Attachments B4 contain the composite motor curves based the output of MathCAD (Attachment B3) for the motor impedance models. Below are a summary of the results identifying the following:

- Torque, current, and power factor versus speed curves depicting a comparison of the unique motor characteristics for each service versus the composite curves of that motor service.
- The final impedances in percent per unit to provide the best curve fit of the motor impedance model curves to the composite curves.
- A comparison of the acceleration times of the motor impedance models versus the vendor data.
- A comparison of torque, current, and power factor of the impedance models in MathCAD versus the vendor data ETAP.

The Auxiliary Feedwater Pump Motor impedance model was provided by the motor vendor and is, therefore, not included in the results below.

Section II – Motor Dynamic Impedance Models

II.8 CONCLUSIONS

The calculation determined a composite motor nameplate and composite motor curves which established bounding motor performance characteristics for a given service (SI, SW, RHR, CCW, CS, and CAF). The composite motor information was utilized to establish the motor impedance model for each service which provides motor performance characteristics which bound the vendor data.

The motor impedance model was determined to be acceptable which was verified by a motor dynamic starting analysis performed in ETAP. The motor performance characteristics were compared to the composite motor curves for each motor service. In all cases the motor performance characteristics as calculated by ETAP based on the motor impedance model were primarily more conservative than the composite motor curves, i.e., equal to or lower torque versus speed curve, equal to or higher current versus speed curve and equal to or lower power factor versus speed curve as shown in section II.7.05. In a number of cases, the ETAP curves exhibited a slight non-conservative overlap that are considered to have a negligible impact on transient analyses and determined to be acceptable. Therefore, Acceptance Criteria II.3.02, II.3.03 and II.3.04 which allows a small tolerance have been met. In addition, the acceleration time of motors as calculated by ETAP and the open circuit time constant based on the motor impedance model were compared to the vendor data. In all cases the acceleration time and open circuit time constant of the developed motors was greater with a slight positive tolerance than the vendor's data.

The motor impedance models have been demonstrated to be more conservative then the vendor supplied data for the motors in each of the specific motor services. Acceptance Criteria II.3.01, II.3.02, II.3.03, II.3.04 and II.3.05 have been satisfied. Therefore, it is concluded that the motor impedance models developed are acceptable for use in the EDG Transient Loading Analysis and Voltage Decay Analysis.

Section III – AC Electrical System Model in ETAP for Transient Loading Analysis

III. AC ELECTRICAL SYSTEM MODEL IN ETAP FOR TRANSIENT ANALYSIS

III.1 PURPOSE AND SCOPE

III.1.01 PURPOSE:

The purpose of this calculation is to develop and maintain an AC electrical distribution system model in ETAP (Reference VI.3.01), to perform electrical system transient analysis. The electrical distribution system model will include equipment powered by the safety related system (buses 1A-05, 1A-06, 1B-03, 1B-04, 1B-30, 1B-32, 1B-39, 1B-40, 1B-42, 1B-49, 2A-05, 2A-06, 2B-03, 2B-04, 2B-30, 2B-32, 2B-39, 2B-40, 2B-42, and 2B-49) that will be evaluated within the transient analysis. The electrical distribution system model will include ratings and performance data that were developed in the Master Input Calculations (Reference VI.1.01 and VI.1.02) and various other references. The calculation also models the operational scenarios that will be used for the various electrical system analyses. The electrical distribution system model will be used to perform the Emergency Diesel Generator (EDG) Transient Analysis and Voltage Decay Analysis for the safety related buses. Additionally, this calculation will ensure the electrical distribution system model is controlled and maintained.

III.1.02 SCOPE:

The scope of the Electrical Distribution System Model for Transient Analysis will only include the equipment to be dynamically modeled within ETAP. A limitation in ETAP requires that all equipment within the model include the dynamic equipment parameters required even if the equipment is off in all operating conditions. Therefore, due to the limitation in ETAP, the following scope is included in this calculation:

Only the safety related equipment powered by the following switchgear 1A-05, 1A-06, 1B-03, 1B-04, 2A-05, 2A-06, 2B-03, and 2B-04 are modeled (See section III.5.05)

The safety and non-safety related equipment listed in section III.5.05 powered by MCCs 1B-30, 1B-32, 1B-39, 1B-40, 1B-42, 1B-49, 2B-30, 2B-32, 2B-39, 2B-40, 2B-42, and 2B-49 are modeled. See methodology section III.2.01 item 1 for further detail.

Section III – AC Electrical System Model in ETAP for Transient Loading Analysis

III.2 METHODOLOGY

Note: The methodology utilized in the calculation section is not described within the current licensing basis (CLB) (e.g. FSAR).

III.2.01 MODEL DEVELOPMENT:

The PBNP electrical system to be evaluated for transient analysis is modeled in ETAP and includes the equipment powered from the safety related 4.16kV switchgear, 480V Switchgear and 480V Motor Control Centers (MCC). The base model was built utilizing the system single line drawings (References VI.5.01 through VI.5.313) and the AC Master Input Calculations (reference VI.1.01 and VI.1.02) as a reference for the topology of the system. The base model topology was developed as follows and the schematic diagrams (single line drawings) from ETAP are in Attachment C1:

1. Each circuit was modeled individually for the circuits listed in section III.5.05. The circuits listed in section III.5.05 contain all the safety related equipment powered from 4.16kV and 480V switchgear; and contains the safety and non-safety related loads powered from the safety related 480V MCCs that would automatically restore after a loss of offsite power. The individual circuits being modeled within this calculation are the loads that would automatically be loaded onto an EDG after a loss of offsite power event. This is determined by reviewing the schematic diagrams for all circuit supplied by 1A05, 1A06, 1B03, 1B04, 1B30, 1B32, 1B39, 1B40, 1B42, 1B49, 2A05, 2A06, 2B03, 2B04, 2B30, 2B32, 2B39, 2B40, 2B42 and 2B49. ETAP requires that all equipment within the model to include the dynamic equipment parameters required even if the equipment is off in all operating conditions. Therefore, as a result of the limitation within ETAP, only the loads that are automatically loaded onto the EDG are individually modeled within ETAP (See section III.5.05 for list of loads). In addition, see section V.2.01 for the basis of the model supporting Voltage Decay Analysis. Each circuit contains a protective device, cable and load as applicable. The cables for individual loads are modeled in ETAP as part of the load device for Induction Motors and Static Loads.
2. Each circuit that was not individually modeled within the calculation will include a list of breakers and the loads they supply for reference.
3. Modeling Techniques: Individual nodes were added as required between cables and devices as required by ETAP to allow connection to occur. Additionally, single-throw switches were utilized as placeholders for the cubicle supporting the B-03 to B-04 crosstie. No technical data except voltage is required for the individual nodes and single-throw switches utilized for modeling techniques.
4. Instrument, lighting and small miscellaneous transformers are modeled as static load devices (ETAP device name) when fed by MCCs. Assumption III.4.01.3 addresses this modeling technique.
5. Alternate Safe Shutdown Alignment: Several safety related motors fed from the 480V safety related switchgear that may be alternately fed from non-safety related switchgear B-08 and B-09. These motors may be fed from either path via a manual transfer switches or molded case switches. For the purpose of this calculation, the manual static transfer

switches will be modeled as individual nodes with a voltage rating equivalent to the system voltage because the alternate path is not within the scope of this calculation and modeling the switch as a node will not impact the results of the calculations performed.

6. Offsite Power Source: The offsite power source will be modeled with a Power Grid within ETAP. The offsite power source is established to conservative simulate a stiff source with a constant voltage on the safety 4.16kV bus with no voltage variation as a result of bus loading. Therefore, the Power Grid is established for each 4.16kV bus with a rating of 999999 MVASC and 9999 X/R which will provide a stiff source in ETAP. This will not impact the EDG transient analysis because offsite power source is not utilized. This is conservative for the voltage decay analysis to establish the worst-case source voltage.

III.2.02 TECHNICAL DATA ENTRY:

The equipment technical data entered into the model was based on the required fields described in Section III.5.02. Special considerations are required for certain equipment and the methodology used is as follows:

1. Emergency Diesel Generator (EDG): The nameplate information input into the model for Emergency Diesel Generators are Rated kW, Rated Voltage, and Rated kVA. The nameplate rated kW and rated kVA of the generator remained fixed and the power factor is calculated by ETAP based on the input parameters to satisfy the standard engineering equation within ETAP. A subtransient model of the EDG is utilized in ETAP to represent the dynamic model of the EDG. This provides a comprehensive representation of a synchronous machine including both the transient and subtransient parameters. The initial EDG data is based on section III.5.02.8 which is based on manufacturer data and standard data for an EDG. However, the EDG, exciter and governor parameters will be adjusted to match the performance of the EDG's during surveillance testing as documented in Section IV. The adjustments are made to the parameters to provide the best calculated EDG dynamic response to match the installed equipment.
2. Circuit Breakers: The only information placed into the ETAP model for transient calculations is the circuit breaker rated current and rated voltage. The transient analysis requires that there to be an impedance between two buses/nodes. There are several cases were there would be a breaker separating two buses/nodes. A bus/node was placed on the secondary side of the breaker to allow the breaker to feed multiple loads based on the configuration of the plant. Therefore, to meet the requirements of the transient analysis in ETAP, a cable is included with an impedance of 0.0001+j0.0001 ohms with a cable length of 1 foot will be utilized in cases where there is only a breaker between 2 nodes. The cable ID will be established with the letter D with the cubicle ID. The addition of this cable will have a negligible impact on the results of the calculation since the additional impedance is relatively small and therefore meets the requirements of ETAP.
3. Induction Motors (Fed from 480V MCC): The nameplate information input into the model for induction motors are Horsepower, Rated Voltage, Percent Power Factor at 100% load, Poles, Full Load Amps,

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and rated full load RPM. The nameplate current of the motors will remain fixed and the percent efficiency at 100% load is calculated by ETAP based on the input parameters to satisfy the standard engineering equation (equation III-1) for efficiency within ETAP. The transient analyses require the motor impedance models to be developed to evaluate the affects of the motors on the system for motors being dynamically modeled. Motor impedance models will be developed for motors equal to or greater than 1 HP (Assumption III.4.01.6). Therefore, to develop the motor impedance models for motors fed from 480V MCCs ETAP's parameter estimation module is utilized to calculate the motor impedance models. The ETAP parameter estimation module calculates480 the equivalent circuit model parameters based on advanced mathematical estimation and curve fitting techniques based on machine performance characteristic data. The motor impedance model parameter estimation calculation method is based on reference VI.2.05. ETAP's parameter estimation module requires the following inputs: motor nameplate information (Percent power factor at 100% load, Percent efficiency at 100% load and Motor rated speed), locked rotor torque, locked rotor current, locked rotor power factor and breakdown torque. Than ETAP parameter estimation module is utilized to calculate the motor impedance module based on a solution precision of 0.1% and an acceleration factor between 0.05 and 0.15 are utilized. The solution precision is the allowable deviation of the ETAP calculated values and a value of 0.1% will closely model the characteristics of the motors. The acceleration factor is the convergence acceleration factor used between iteration and a value 0.05 and 0.15 is sufficient to develop the motor impedance model to ensure a solution is determined. ETAP's parameter estimation module calculates motor circuit impedance model and remaining motor parameters (X/R, 50% and 75% of load power factor and efficiency). Additionally, motors W-085 and W-086 are modeled on high speed (25 HP – 1745 RPM versus 12.5 HP – 857 RPM) to provide the worst-case loading and impact on the electrical distribution system.

$$EFF = \frac{0.746 * HP}{\sqrt{3} * V * I * PF} \qquad \text{Eq III-1}$$

Where:

EFF = Efficiency
HP = Horsepower
V = Phase-to-Phase Voltage
I = Phase Current
PF = Power Factor

4. Induction Motors (Fed from 4.16kV and 480V Switchgear): The induction motors fed from the switchgear are based on a composite motor for each motor service (SI, SW, CCW, etc.). The composite motor consists of an ETAP Induction Machine device and an ETAP Lumped Load Device. The combination of these two devices will provide the dynamic response of the motors as provided by the manufacturer. The composite motor technical data was developed to envelop the characteristics of the individual motors within a service and

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determined in Section II of this calculation. The nameplate information input into the model for induction motors are Horsepower, Rated Voltage, Poles, Full Load Amps, and rated RPM based on the composite motor data. The transient analyses require the motor impedance models to be developed to evaluate the affects of the motors on the system. The motor impedance models for each service were developed in Section II and placed in the ETAP library for the ETAP Induction Machine device (see Item 9). The appropriate motor impedance model is placed in the model for each service. ETAP's calculates the remaining motor parameters (power factor, efficiency, locked rotor current, locked rotor torque, X/R, etc.) based on the motor impedance model selected. The ETAP Lumped Load device will be placed in the system as a 100% constant impedance device with the parameters determined in Section II. The lumped load device is identified as a shunt impedance Z_{sh} in Section II of the calculation. This provides the enveloping composite motor data to perform transient analyses.

5. AFW Motors and Cables: *This calculation is evaluating the impact of* modification EC1565 and EC1566 (Ref VI.4.09) which replaces the motors and supplies the AFW motors from the 4.16kV switchgear. The AFW power supply cables will consider 2 cables to evaluate the minimum length for voltage decay analysis and maximum length for EDG transient analysis. This provides the worst-case condition for each analysis. The cables will be modeled with a switch on both sides of the cable. The status of the switches will be dependant on the scenario being performed. The maximum cable length is based on Input III.5.02.3 and the minimum length will established as 1 foot to provide the worst-case minimum length. The motor nameplate information that is inputted into the model for the AFW motor are Horsepower, Rated Voltage, Poles, Full Load Amps, and rated RPM based on the vendor data. The motor rated voltage and rated current are entered equal to the voltage base and current base of the per unit motor impedance model. This ensures ETAP calculates the same motor model in ohms as the manufacturer. The transient analyses require the motor impedance models to be developed to evaluate the affects of the motors on the system. The AFW motor impedance model is provided by the vendor, which is similar to a Single2 model in ETAP. The following are minor modification: The vendor provides the motor core loss resistance, however ETAP Single2 model neglects the core loss resistance. This is acceptable and will have a minor impact on the transient analysis because the motor core loss resistance is approximately 10 times the magnetizing reactance which is in parallel. Therefore, the majority of magnetizing or exciting current will flow through the magnetizing reactance and excluding the core loss resistance will have a negligible impact on the transient response of the AFW motor.
6. Static Loads: ETAP requires that the standard engineering equations be satisfied for the load nameplate. The nameplate information for static loads consists of Rated Voltage, kVA, kW, kVAR, Full Load Amps, and power factor. The rated voltage must always be entered. The remaining parameters are derived based on which parameters are "hand-entered." For example, if the Voltage, kW and power factors are hand-

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entered, then the kVA, kVAR and amps are determined from the equation by ETAP.

7. Overload Heaters and Non-Safety Related Cables: The overload heaters and cables are entered into the model based on the information provided in the Master Input Calculations (Reference VI.1.01, VI.1.02). However, if the non-safety related cable information is unknown (cable length, cable size, etc.), they are not modeled. The cables not being modeled will have a negligible impact on the transient analysis because the loads are mostly static loads which will provide a larger load since voltage drop across the cable will be neglected. Therefore, not modeling the non-safety related cables will have a negligible impact on transient analysis performed. Overload heaters with multiple different type heaters will be modeled based on the largest impedance. This is conservative for transient analysis calculations because the larger impedance provides a greater voltage drop across the device which in turn impacts motor starting. In addition, this is conservative for EDG loading because the addition impedance will provide a larger load as a result of the losses through the overload heater.
8. Data for Motor Operated Valves (MOV) for Motor Starting Analysis: A transient analysis is performed to evaluate automatic loading onto the EDG to ensure a successful start of safety related motors and successful operation of the EDG after a loss of offsite power with or without a loss of coolant accident (LOCA). MOVs that receive an automatic signal to start change state during a LOCA or a loss of offsite power (LOOP) will create additional load on the safety related buses. To account for the additional load of the MOVs, they are modeled in a stalled (locked rotor current) condition for the total duration of the event being evaluated. Therefore, the stroke time of the valves will be placed as 100 seconds which is greater then the total sequence time to be evaluated. This will provide the worst-case loading conditions as a result of the movement of the MOV. During transient analyses the MOV loading provided within the analysis is based on the information contained within "Characteristics" which define the current, percent power factor and stroke time utilized. The nameplate information is required to be placed in the model; however the information is not utilized to perform transient analyses. Therefore, the nameplate horsepower and rated voltage will be entered based on input III.5.02.12 and an efficiency of 50% and a power factor of 80% will be arbitrarily chosen. This will automatically calculate the full load amps. In addition, the number of poles will be arbitrarily chosen as 4 and is not utilized to perform the analysis. Since the transient analysis utilizes the "characteristics" when an MOV is started the arbitrary values chosen for efficiency, power factor, and number of poles will not impact the analyses. Note: The MOV voltage requirements are evaluated by the GL.89-10 MOV program, therefore the MOV terminal voltage requirements are not evaluated within the scope of ETAP related calculation. (See section III.5.02.12 for input data)
9. ETAP Library Information: ETAP Library "Calc2005-0007" created for this calculation to provide the required equipment data for overload heaters, cable impedance and motor circuit models The following ETAP library data and associated references are as follows:

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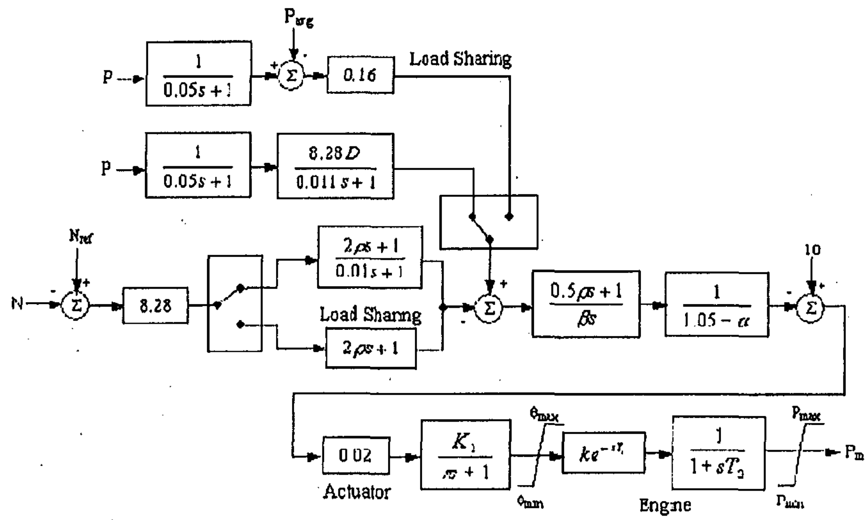
- FH and H Overload Heaters: The overload heater resistance used was obtained from reference VI.4.13 of Calculation 2003-0007 (reference VI.1.02). The overload heater resistances were entered into PBNP ETAP library (Library – Calc2005-0007.lib). The overload heater resistance was then selected as appropriate for the specified circuit. This will match the overload heater resistances contained in the Master Input Calculation. The overload heater resistances provided by the vendor for type FH and H heaters were provided for use in engineering calculations and provide a minimum and maximum resistance value. These resistances account for various tolerances including temperature. Values were not added for the "App.", "Nom. R" or "%Tol" columns. The "App." Field describes the intended application of the heater and is not required. The "Nom. R" and "%Tol" are calculated by ETAP based on the minimum and maximum resistances. The "Min Amp," "Max Amp" and "Trip Amp" are placed at zero because the trip amps are not utilized within this calculation.
- Cable Impedance: The cable impedance used in the Master Input calculation for all cables is contained in Attachment A of References VI.1.01 and VI.1.02. The cable impedance specified in Attachment A was placed into a PBNP ETAP library (Library – Calc2005-0007.lib). The cable impedances were then placed into the model based on the cable size and route of the circuit. This matches the total cable impedance value contained in the Master Input Calculations. The U/G Ampacity parameters (Ta = 20C, Tc = 90C, RHO = 90), A/G Ampacity Parameters (Ta = 40C, Tc = 90C) and Insulation Parameters (Type = Rubber and %Class = 100%) were placed into the library as placeholders and these parameters do not impact the cable impedances which are utilized within the transient analysis.
- Motor Load Model: The load dynamic characteristics (Speed versus Torque curves) of the fans, pumps and compressors are provided in assumption III.4.01.7. The dynamic data for each type of load (fan, pump and compressor) was entered into the Motor Load Model Library in the ETAP library (Calc2005-0007.lib). The load curves were entered as Model Type – Curve and labeled as PBNP-FAN, PBNP-PUMP and PBNP-COMP.
- Motor Circuit Model: The ETAP Transient Module (Reference VI.3.01) requires the motors to be entered based on the motor impedance model. Therefore, section II developed the motor impedance model for the safety related motors supplied from the 4.16kV and 480V Switchgear. To select a motor impedance model for a give service the motor impedance model is required to be entered into the ETAP Motor Circuit Model Library. Therefore, the motor impedance models were entered into the ETAP Motor Circuit Model Library for a given model type (Singel, Single2 or DBL1&DBL2) by defining a Design Class "PBNP" and labeling the Model ID based on the appropriate service. The motor impedance models required inputs are provided in Section

III.5.02.9. Also see section III.2.02 item 4 above for discussion of composite motor for a given service.

10. The EDG Governors for G-01, G-02, G-03, and G-04 are Woodward type 2301A electronic governors (References VI.5.314, VI.5.315, and VI.5.316). The governor for the EDG's will utilize the transfer function contained within the ETAP library. The parameters for the governors will be developed within section IV. The transfer function utilized by ETAP is as follows:

Woodward Governor 2301

This type of governor-turbine system represents the Woodward 2301 and 2301A speed governing systems with a diesel turbine system and load sharing capability.



Woodward Governor 2301A and 2301 (2301)

Parameter Definitions and Units

Parameter definitions and their units are provided in the following table:

Parameter	Definition	Unit
Mode	Droop or Isoch	
LS GP#	Load sharing group number	
Droop	Steady-state speed droop in second	%
θmax	Min. shaft position in degrees	Deg
θmin	Max. shaft position in degrees	Deg
α	Gain setting	
β	Reset setting	
ρ	Actuator compensation setting	
K1	Partially very high pressure power fraction	Deg/A
τ	Actuator time constant	Sec.
T1	Engine Dead Time constant	Sec.
T2	Amplifier/compensator time constant	Sec.
Pmax	Maximum shaft power	MW
Pmin	Minimum shaft power	MW
k	Internal variable (= MVA/(θmax-θmax))	MW/Deg

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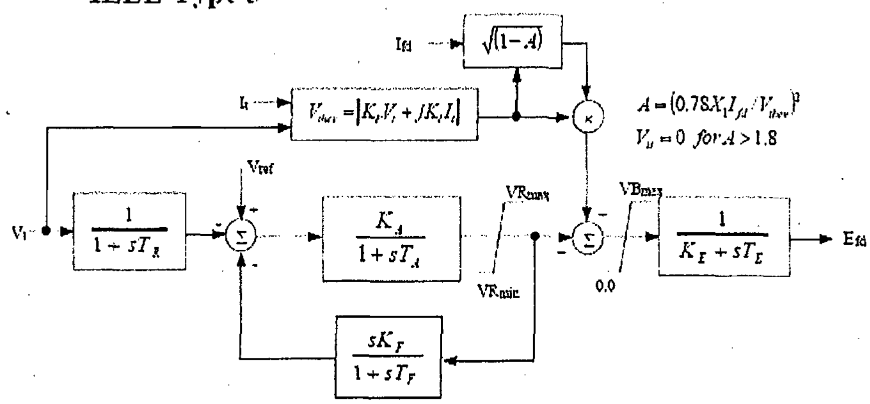
11. The EDG Voltage Regulator / Exciters for G-01, G-02, G-03 and G-04 (VI.4.11 and VI.4.12) are static type systems with compound terminal voltage and current inputs similar to an IEEE type 3 type of excitation system (reference VI.3.01). The exciters for the EDG's will utilize the transfer function within the ETAP library. The parameters for the exciters will be developed within section IV. The transfer function for an IEEE type 3 exciter utilized by ETAP is as follows:

IEEE Type 3



IEEE Type 3 - Static System with Terminal Potential and Current Supplies (3)

Parameter Definitions and Units

Parameter definitions and their units are provided in the following table:

Parameter	Definition	Unit
VRmax	Maximum value of the regulator output voltage	p.u.
VRmin	Minimum value of the regulator output voltage	p.u.
VBmax	The value of excitation function at Efdmax	p.u.
KA	Regulator gain	p.u.
KE	Exciter constant for self-excited field	p.u.
KF	Regulator stabilizing circuit gain	p.u.
KI	Current circuit gain coefficient	
KP	Potential circuit gain coefficient	
XL	Reactance associated with potential source	
TA	Regulator amplifier time constant	Sec.
TE	Exciter time constant	Sec.
TF	Regulator stabilizing circuit second time constant	Sec.
TR	Regulator input filter time constant	Sec.

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III.2.03 DEVELOPMENT OF CIRCUIT DEMAND FACTORS:

The individual circuit demand factors developed in this section are rounded (Maximum Demand Factor is round up to the nearest whole number and Minimum Demand Factor is rounded down to the nearest whole number) to the nearest whole number, as appropriate, to meet data requirements for ETAP.

III.2.03.1 Voltage demand factor for the EDG and Offsite Power

ETAP has 10 different generating categories to allow different operating states for the Grid and generators in the system. The following are the defined generating categories used in the base model:

- Design: Normal operating voltage
- Max Voltage: Maximum system operating voltage
- Min Voltage: Overall minimum system operating voltage

The following fields are defined for each operation mode for each generating category:

- Swing Mode: Percent Voltage and Voltage angle
- Voltage Control: Percent Voltage, Mega-Watts, Reactive Power Minimum and Reactive Power Maximum
- MVAR Control: Mega-Watts and Reactive Power (MVAR)

Emergency Diesel Generators (G-01, G-02, G-03, and G-04) and Offsite Power

The emergency diesel generators will automatically be loaded a loss of offsite power. The transient module in ETAP requires at least one source to be in Swing Mode. Therefore, the emergency diesel generators are modeled in Swing mode. The voltage angle for each generating category is 0 degrees. The voltage angle is used as a reference point throughout the system and will not affect the results of the calculation. The following is the percent voltage for each category:

Design: 4.16 kV – The design category is an operating voltage during normal plant operation. 4.16kV is the nominal voltage in which the EDG operates at during operation when automatic operation.

Max Voltage: 4.569 kV – This would be the maximum 4.16 kV system voltage possible based on the maximum Gas Turbine voltage (14.4 kV) and the transformer tap settings. This provides the worst 4.16 kV system voltages neglecting the voltage drop through the system. The Gas Turbine operating at its maximum voltage bounds the maximum 345kV system (362 kV) without the Gas Turbine in operation. (Reference VI.1.01, VI.7.13, and VI.7.21)

Min Voltage: 4.05 kV – This is the minimum allowable operating voltage of the EDG per operating procedures (reference VI.7.14, VI.7.15, VI.7.16, and VI.7.17).

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Bkr Closure: 3.744 kV – This is the minimum allowable voltage at which the EDG output breaker will close and be automatically loaded on the safeguards buses. The A-train EDGs output breaker closure are designed to be at a voltage greater than 90% of nominal voltages and are confirmed each outage per procedure (Reference VI.7.18 and VI.7.19). The B-train EDGs output breaker closure is based on voltage monitor relays which ensure the voltage is greater than 3931 volts (Reference VI.1.07). Therefore, it is conservative that the minimum voltage at breaker closure will be 3744 volts.

III.2.03.2 Demand Factors for the 4.16 KV Circuits

The only safety related circuit fed from the 4.16 KV system is the safety injection pump motors and the auxiliary feedwater pump motors (reference VI.4.09). The safety injection pump is typically OFF during normal plant operation unless a surveillance test is being performed. The safety injection pump motor starts and loads to the bus during a LOCA event. The minimum demand factor for the safety injection pump is based on the manufacturer's pump curve by obtaining the most limiting brake horsepower on the pump curve (Reference VI.4.02). The maximum demand factor for the safety injection pumps are based on the maximum brake horsepower under worst-case flow conditions during operation of the pumps per Reference VI.1.04.

The auxiliary feedwater pump is typically OFF during normal plant operations unless a surveillance test is being performed. The auxiliary feedwater pump motor is utilized in modes 2, 3, and 4 when chemical additions or small feedwater flow requirements do not warrant the operation of the main feedwater and condensate systems. In addition, the auxiliary feedwater pump will automatically start and deliver adequate flow to maintain steam generator level upon receipt of an initiating signal (e.g. low steam generator level, ATWAS, safety injection signal, etc.). The minimum and maximum demand factors for the auxiliary feedwater pump are based on requirements of the AFW System per Reference VI.4.09.

III.2.03.3 Demand Factors for 480 V Circuits

The minimum and maximum demand factors for the 480 V circuits are developed to provide the worst-case minimum and maximum loading for transient analysis. The minimum and maximum demand factors for the circuits are developed as follows:

- The non-safety related circuits and the safety related circuits supplied by the MCCs (1B-30, 2B-30, 1B-32, 2B-32, 1B-40, 2B-40, 1B-42 and 2B-42) that are powered by the safety related buses which will automatically be loaded onto the EDG after a LOOP are modeled with a demand factor of 100% to evaluate for maximum load conditions for transient analyses. This will provide the worst-case loading for the non-safety related circuits and safety related circuits, because typically loads are designed to operate equal to or less than their nameplate rating. The minimum demand factor of 0% will be utilized for circuits fed from the MCC's which will provide the worst-case minimum loading for transient loading analyses (Assumption III.4.01.4)

- The safety related circuits supplied by the switchgear are modeled based on the maximum brake horsepower under worst-case flow conditions during operation of the pumps per references VI.1.04, VI.1.05, and VI.1.06 . The minimum demand factor for the 480V switchgear pumps is based on the manufacturer's pump curve by obtaining the most limiting brake horsepower on the pump curve. This provides the worst-case minimum and maximum loading for transient analysis.
- The lighting transformers supplied by the MCCs (1B-30, 2B-30, 1B-32, 2B-32, 1B-40, 2B-40, 1B-42 and 2B-42) that are powered by the safety related buses which will automatically be loaded onto the EDG after a LOOP are modeled with a maximum demand factor equivalent to the maximum connected electrical load based on drawings or based on the KVA rating of the transformer. The minimum demand factor of 0% will be utilized for lighting transformers fed from the MCC's which will provide the worst-case minimum loading for transient loading analyses (Assumption III.4.01.4)

III.2.03.4 Equipment Demand Factors Entered into Base Model

The demand factors for each equipment established in the previous sections were entered into the Loading Category, in ETAP, for each equipment with a status of "On" in the operating conditions being evaluated. The following Loading Categories are utilized:

- Design
- Minimum DF
- Maximum DF
- ORT 3 Load

The Loading Category – Design maintains all the equipment modeled "ON" within the base model to establish the total connected load for a bus during different plant operating conditions. The Loading Category – Minimum DF is the minimum demand factor for the equipment that is modeled as "ON" for any plant-operating scenario being evaluated. This category will be used to evaluate the maximum voltage decay for the 4.16kV and 480V switchgear. The Loading Category – Maximum DF is the maximum demand factor for the equipment that is modeled as "ON" for any plant-operating scenario being evaluated. This category will be used to evaluate worst-case loading when supplied by the EDG after a LOOP with or without a LOCA. The Loading Category – ORT 3 Load is the demand factor for the equipment utilized in tuning the EDG in Section IV.

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III.2.04 DEVELOPMENT OF PLANT OPERATING CONDITIONS (SCENARIOS):

III.2.04.1 Development of status for each circuit

The development of the operating scenario's and status for each circuit will be developed for each transient analysis performed. Note: Section IV will develop the operating scenarios for EDG transient analysis and Section V will develop the operating scenarios for the Voltage Decay analysis. The general guidelines in the development of the equipment status for operating scenario's will be as follows:

- The status of each equipment, "ON" or "OFF", will be based on the status of the protective device feeding the service
- Motor Operated Valves (MOVs) that change were determined by a review of plant drawings (Reference VI.5.155 through VI.5.194). The operation of the MOVs during a LOCA is taken into account in the transient analyses and the Info Page – Demand Factor for Open and Closed states are listed as 100% to account for loading during transient analyses. The initial statuses of the MOVs are based on plant operating system checklists. MOVs status-dependent on Shift Manager discretion are modeled in the conservative state in which they change position in a LOCA. Therefore, if an MOV changing state will be included in the scenario the protective device will require to be statused as Closed and ETAP requires that the breaker of the equipment to be started must be closed. Therefore, the Motor Operated Valves (MOVs) that change state (Open or Close) will have a breaker status of "ON" to ensure the MOVs are accounted for during the motor starting condition. However, the MOV Loading Category Demand factor will be 0% for static loading since MOVs operate for short durations and meet the definition of "OFF" by operating for less than 2 minutes per hour. The demand factor of the MOV during the transient analysis is contained in the characteristic section of the MOV.

III.2.04.2 Plant Operating Conditions Modeled (Case)

The case studies and the equipment status for each case study in the base model are developed in Section IV (EDG Transient Analysis) and Section V (Voltage Decay Analysis). The worst-case plant alignments will be developed based on the guidance provided in Section III.2.04.1. Each case study was determined to evaluate the worst-case condition for each individual unit.

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III.2.04.3 Development of Study Cases for model

The study case for each type of analysis contains, as applicable, the solution control variables, loading conditions, tolerance adjustments, faulted bus selection, motor starting events, prestart loading conditions and a variety of options for output reports. The following is the general set-up of the study case for Transient Analysis.

Transient Analysis Study Case Development

a. Max. Iteration: 20
   Specified number of maximum iterations the program will calculate convergence of the solution has not been met for the initial load flow.
b. Solution Precision: 0.0000000001
   The precision is compared with the difference in power for each bus (MW and MVAR) between iterations for the initial load flow. If the difference between iterations is less than or equal to the value entered for the precision, the desired accuracy is achieved. The solution precision utilized will result in a negligible difference in the voltage at the bus.
c. Acceleration factor: 1.45
   This is the convergence acceleration factor used between iterations.
d. Simulation Time Step: 0.001 seconds
   A time step of 0.001 seconds shows the expected system response during dynamic motor starting. A time step of 0.001 seconds provides adequate resolution to capture the dynamic response of the system without producing excessive amounts of output data.
e. Plot Time Step: 10 x dt
   This value determines how often ETAP records the results of the simulation for plotting. Therefore, 10 times the simulation was chosen to capture significant events.
f. Apply Transformer Phase-Shift: No
   PBNP does not have any transformers that would require a phase shift to be applied; therefore the item is unchecked.
g. Loading Category: Maximum DF or Minimum DF
   The loading category is chosen based on the analysis being performed. The Maximum DF category provides the maximum demand factor for equipment to establish the worst-case loading for transient

analyses and the Minimum DF provides the minimum demand factor for equipment to establish the worst-case minimum loading for transient analyses.

h. Generation Category:

   The generator category is chosen based on the analysis being performed.

i. Charger Loading: Loading Category

   There is no battery chargers within the model developed in this calculation. Therefore, the Charger Loading is placed in loading Category.

j. Load Diversity Factor: None

   No field is checked. The demand factors applied to the equipment in the system are determined based on the loading category. No additional global or bus diversity factor is required.

k. Events

   The events group specifies the events according to the time of occurrence.

l. Actions

   The action group allows any system change or disturbance for a given event group. An action could be starting or stopping a motor, opening or closing a breaker, etc. An action will be based on the element type (Motor, MOV, Gen/Power Grid, or breaker), action (Start or stop, Open or Close) and equipment information (equipment ID and Starting Category)

m. Total Simulation Time

   The total simulation is determined to ensure the complete dynamic response is captured and the system returns to steady state conditions and is based on the timing sequence of loads after the initiation of the event.

n. Plot

   The plot page is used to allow the user to determine which equipment/device that are dynamically modeled will be tabulated at the end of the transient stability output report and stored in the plot file to be plotted. The user places a check in the box to mark which equipment/device is tabulated. All critical equipment should have data tabulated.

o. Dynamic Modeling: Model Machines Larger or Equal to 1 HP/KW

   The dynamic modeling in ETAP determines which equipment ETAP will dynamically model when performing the transient analyses. PBNP only has medium voltage and low voltage induction machines dynamically modeled. All induction machines are dynamically modeled greater than 1 HP and therefore 1 HP/KW is chosen to have ETAP dynamically model all induction machines within the transient analysis greater than 1 HP.

p. Dynamic Modeling During Simulation (Time >0): Both unchecked

PBNP does not have any load tap changing transformers or starting devices within the safety related system modeled within this calculation; therefore the items are unchecked.

q. Starting Load of Accelerating Motors: Yes – Based on Motor Mechanical Load

The load torque model will be applied directly based on the required brake horsepower and the load curve will be applied directly without any adjustments.

r. Constant Power Load – Threshold Voltage (VLC Limit): 75%

The threshold voltage is used to control automatic conversion of a constant kVA load to a constant impedance load for transient stability calculations. If the connected bus voltage is below this value, a load type conversion will occur for all applicable loads. A threshold voltage of 75% voltage was chosen because this is the minimum voltage at which a running motor is guaranteed to operate for 60 seconds or less. The threshold voltage limit only impacts motor Z-103 because it is the only motor that is not dynamically modeled since its less than 1 horsepower. If a motor is dynamically modeled, the motor circuit model is utilized to determine the response of the motor. Therefore all other motors are not impacted by the voltage threshold limit.

s. Constant Power Load – Delta V: 2%

To avoid sudden jump during the load type conversion, a 2% of the voltage margin may be added to make an undetermined region of VLC Limit +/- 2%, which means if the connected bus voltage drops below VLC Limit -2%, a constant kVA load is to be converted to constant impedance load. On the other hand, if the connected bus voltage recovers about VLC Limit +2%, the load is to be converted back to a constant KVA Load. A delta of 2% provides sufficient value to prevent a sudden jump during load type conversion.

t. Reference Machine: None (unchecked)

u. Synchronous Machine Damping: Use Weighted Machine Frequency

An equivalent network frequency will be calculated by taking the weighted average of the speed of the synchronous generators that are in the system. This equivalent frequency is then used in the swing equation to calculate the machine-damping power. This option is checked when a system does not have a "power grid" and thus the network frequency is not guaranteed to remain constant during the transient. This is utilized to best model the system during transient analyses.

v. Impedance Tolerance – Transformer: No

w. Impedance Tolerance – Reactor: No

x. Length Tolerance – Cable: No

y. Length Tolerance – Transmission Line: No

z. Resistance Temperature Correction – Transmission Line: No

Tolerance items v, w, x, y, and z: The tolerances provide an adjustment to the characteristic being evaluated in the motor starting analysis. The above impedance and length tolerances are primarily for initial design analysis and are not considered because installed impedances and lengths are entered into the model.

aa. Impedance Tolerance – Overload heater: Yes – Individual

bb. Resistance Temperature Correction – Cable: Yes – Individual

Tolerance items aa and bb account for the tolerance of overload heater resistance and the temperature at which the resistance values are determined

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III.3 ACCEPTANCE CRITERIA

There are no applicable acceptance criteria. This calculation only develops the electrical system model in ETAP that will be used to perform the EDG Transient Load Analysis and Voltage Decay Analysis.

III.4 ASSUMPTIONS

III.4.01 VERIFIED ASSUMPTIONS

III.4.01.1 It is assumed that lighting transformers, instrument transformers and miscellaneous transformers supply loads with a power factor of 90%.

Basis: The power factor for the lighting loads range from90% to 100% based on the type of lighting loads that are considered per Reference VI.2.01. Therefore, conservatively a power factor of 90% is used to represent the power factor for the ballast in the lighting circuits. In addition, the lighting transformers load is calculated using the KVA rating of the transformer or by the total connected load. This makes the assumed 90% power factor for the lighting transformer conservative further.

The other transformers are also modeled based on their transformer KVA rating or total connected load. The typical loading of these transformers consist of static, lighting or small motor loads. These loads may have power factors other than 90%. However, a 90% power factor is also assumed for these transformers as the transformers are conservatively loaded and a variation from 90% power factor will have a minimal effect on the calculation results.

III.4.01.2 It is assumed that the minimum cable conductor operating temperature is 25°C and the maximum cable conductor operating temperature is 90°C.

Basis: It is conservative to assume a minimum cable operating temperature of 25°C because typically cable operating temperatures will typically range normally from 60°C to 90°C for energized plant equipment because cables are sized typically 60-80% loaded based on ampacity. Therefore, a conservative minimum operating temperature of 25°C utilized, which will result in the minimum cable impedance throughout the system for transient analyses. The majority of power cables installed at PBNP have a normal maximum operating temperature rating of 90°C. The sizing of plant operating cables is based on 90°C to determine if the ampacity of the cable is acceptable. Therefore, all cables are modeled with a maximum operating temperature of 90°C which will provide the maximum cable impedance for transient analyses.

III.4.01.3 It is assumed that instrument, lighting and miscellaneous transformers that are fed from MCCs are modeled as static load devices only (i.e., without a transformer element).

Basis: The loads contained on instrument, lighting and miscellaneous transformers are mostly static loads. In some cases, motors are connected on the secondary side of the transformers

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which have relatively small HP and rated for 120, 208 or 240 volts. Although the motor loads are dynamic in nature, they do not impact the nature of the overall load from static due to their small rating. Therefore, the transformer loads are modeled as a lumped static load for transient analysis.

III.4.01.4 It is assumed that the maximum demand factor for loads powered by buses 1B-30, 2B-30, 1B-32, 2B-32, 1B-40, 2B-40, 1B-42 and 2B-42 are 100%, unless otherwise stated. It is assumed the minimum demand factor for loads powered by buses 1B-30, 2B-30, 1B-32, 2B-32, 1B-40, 2B-40, 1B-42 and 2B-42 are 0%, unless otherwise stated.

Basis: Plant equipment is typically sized to provide sufficient power requirements based on the required power demand (demand factor) of the load. Therefore, the equipment is typically sized based on the next nominal rating to support the required power demand. Therefore it is conservative to assume that the maximum brake horsepower of the equipment is 100% and provides maximum loading for transient analysis (e.g. EDG transient load analysis). The minimum loading of the supplied by the buses above are unknown. Therefore, it is conservatively assuming a minimum loading of 0% which will provide the worst-case condition of minimum loading for transient analysis (e.g. voltage decay analysis).

III.4.01.5 It is assumed that the locked rotor power factor, locked rotor torque, breakdown torque, motor moment of inertia and load moment of inertia are as follows, if the motor data is unknown:

Motor Size	Rated Synchronous Speed	Locked Rotor Power Factor:	Locked Rotor Torque (Percent of Full Load Torque):	Breakdown Torque (Percent of Full Load Torque):	Motor Moment of Inertia:	Load Moment of Inertia:
3 HP	1800 RPM	60%	215%	250%	0.41 LB-FT^2	17 LB-FT^2
5 HP	1800 RPM	N/A	N/A	N/A	N/A	27 LB-FT^2
7.5 HP	1800 RPM	55%	175%	215%	1.03 LB-FT^2	39 LB-FT^2
15 HP	1800 RPM	N/A	N/A	N/A	N/A	75 LB-FT^2
20 HP	1800 RPM	47%	150%	200%	4.3 LB-FT^2	99 LB-FT^2
25 HP / 12.5 HP	1800RPM / 900RPM	N/A	N/A	N/A	N/A	122 LB-FT^2 (25HP 1800RPM)
40 HP	900 RPM	N/A	N/A	N/A	N/A	1007 LB-FT^2

Basis: The MCC motors are dynamically modeled to include the affect of the motors on transient analyses. The above data is required to support creation of the motor impedance model and inertias for each motor. Therefore, the parameters are based on the Motor Size (HP) and rated speed (RPM). The percent locked rotor power factor is typical values for squirrel-cage induction motors based on reference VI.2.03. The locked rotor and breakdown (maximum) torques are minimum required design torque values for design class B motors per NEMA standard MG-1 (Reference VI.2.04). Based on a review of the Master Input Calculation (Reference VI.1.02) of MCC motors installed at PBNP show that motors purchased for PBNP are design class B motors. The locked rotor power factor, locked rotor torque, and breakdown torque are utilized in the development of the motor impedance model. The above data is technically justified in that conservative motor impedance models will be developed based on the minimum required design torques. Slight variations in locked rotor power factor will have minimal impact on the affects of the motor impedance model based on evaluation within ETAP. In addition, the locked rotor power factor, locked rotor torque, and breakdown torque align within the information provided by Baldor in Reference VI.6.01 for the reliance motors installed as shown in section III.5.02.10. The motor moment of inertia (WK^2) is based on typical Westinghouse motor data provided in reference VI.2.02. The load moment of inertia (WK^2) is based on the maximum allowable per NEMA standard MG-1 (reference VI.2.04). This is technically justified since this will provide the worst-case moment of inertia for the installed motors and the worst-case transient response for these motors during motor starting. The voltage decay analysis will not be impacted because as described in section III.2.03.3 the MCC loads have a minimum demand factor of 0%, since ETAP does not take into account frictional losses the moment of inertia does not impact the individual motor affects. Note: If the demand factor is changed to greater than 0% this assumption requires review for voltage decay analyses.

III.4.01.6 It is assumed the motors less than 1 HP will have a negligible impact on the transient analysis.

Basis: Motors less than 1 HP will have a negligible impact on the dynamic response of the safety related electrical distribution system because they are a relatively small load compared to the total load of the 1500 kVA transformers (X-13 or X-14) and/or the total load on the EDG as well as the capacity of 2850 kW of the EDGs. Therefore, the dynamic response of small motors will not impact the transient analysis.

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III.4.01.7 It is assumed the load speed vs. torque for compressors, fans and pumps are as follows:

Fan Load Speed vs. Torque Curve	
Percent of Full Load Speed	Percent of Full Load Torque
0%	20%
5%	11%
10%	2%
15%	4%
20%	5%
25%	7%
30%	9%
35%	13%
40%	17%
45%	21%
50%	26%
55%	32%
60%	38%
65%	45%
70%	52%
75%	60%
80%	67%
85%	76%
90%	85%
92.5%	90%
95%	95%
97.5%	100%

Pump Load Speed vs. Torque Curve	
Percent of Full Load Speed	Percent of Full Load Torque
0%	15%
5%	8%
10%	5%
15%	3%
20%	4%
25%	7%
30%	9%
35%	13%
40%	17%
45%	21%
50%	26%
55%	31%
60%	37%
65%	44%
70%	50%
75%	58%
80%	66%
85%	75%
90%	83%
92.5%	88%
95%	93%
97.5%	97%
98.4%	100%

Compressor Load Speed vs. Torque Curve	
Percent of Full Load Speed	Percent of Full Load Torque
0%	125%
5%	115%
10%	110%
15%	105%
20%	100%
50%	100%
75%	100%
100%	100%

Basis: The load dynamic characteristics (Speed vs. Torque curves) for centrifugal pumps and fans have a characteristic that torque varies as the square of the speed (Reference VI.2.07 and VI.2.08). The pump speed vs. torque characteristics were established by establishing the worst-case speed vs. torque based on the known pump characteristics provide for the switchgear loads. The fan speed vs. torque characteristics were established based on the typical curve based on reference VI.4.08 and VI.2.08 based on the characteristic that torque varies as the square of speed. The torque at zero speed would theoretically be zero, but the motor must overcome stuffing box friction, rotating element inertia, and bearing friction in order to start the shaft turning. This requires a torque at zero speed that may range from 2.5% to 15% of rated full load torque for pumps (Reference VI.2.07) and from 2.5% to 20% of rated full load torque for fans (Reference VI.2.08 and VI.4.08).

Therefore, the torque at zero speed was conservatively chosen to be 15% for pumps and 20% for fans of rated full load torque. This provides a single worst-case characteristic for all pumps and fans. The 100% speed and 100% torque was corrected to a slip of 1.6% for pumps and 2.5% for fans based on the worst-case rated load RPM for pumps and fans powered by the switchgear (Reference VI.4.08). The pump and fan speed vs. torque characteristic would be applicable to the pumps located on the MCC since all pumps of the same speed vs. torque relationship for centrifugal pumps. Note: The full load slip of the motors on the MCC's range from 2.5% to 4.8% based on rated motor RPM. Utilizing a slip of 1.6% for pumps and 2.5% for fans will have a negligible impact on the dynamic response of MCC loads because the loads are 40 HP or less compared to the capacity of 2850 kW EDG's. The EDG starting air compressors (K-004A, K-004B, K-005A and K-005B) Ingersoll-Rand type 30 compressors which are piston driven (positive displacement compressors) (Reference VI.4.11). A positive displacement compressor and positive displacement pump operate under the same principles of compressing a liquid or gas into a pressurized system. Therefore, a positive displacement compressor (like a positive displacement pump) will have a constant torque regardless of the speed with a constant discharge pressure. The torque at zero speed was increased to 125% of full load in order to overcome stuffing box friction, rotating element inertia, and bearing friction in order to start the compressor (Reference VI.2.07).

III.4.01.8 It is assumed that the maximum loading of the containment accident fans (1W-001A1, 1W-001B1, 1W-001C1, 1W-001D1, 2W-001A1, 2W-001B1, 2W2W-001C1, and 2W-001D1) is equal to 150 HP under accident conditions (e.g. LOCA and MSLB).

Basis: The containment accident fans have a fixed volume air flow rate through containment HVAC system since the system resistance to flow remains the same as the HVAC system does not change during plant operations. The BHP of a fan is dependent on the fan speed and the density of the air (or gas) flowing through the system. The speed of the fan will be constant since it is driven by a single speed motor, therefore the BHP of the fans will be directly related to the density of the air flowing through the system. The BHP of the fan is directly proportional to the density of the air flowing through the system. (Reference VI.2.15) The changes in density are impacted by temperature, pressure, altitude, etc. Therefore, the worst-case BHP of the containment accident fans will be determined at the maximum density of the air flowing through the fans during a design basis event (LOCA or MSLB). The worst-case conditions in containment during accident conditions are 286°F, 60 psig and a density of 0.2 lb/ft^3 (Reference VI.4.07). During the Containment Integrated Leak Rate Test (ORT 17 Unit 1 and Unit 2), containment accident fans power requirements are measured at a containment density of 0.2 lb/ft^3 equivalent to worst-case accident conditions. The power consumption during this test would be equivalent to the power consumption during a design basis event (LOCA or MSLB). Based on the completed ORT 17 (Reference VI.4.26), the worst-case BHP is 150 HP (conservatively rounded up). This is equivalent to the motor nameplate rating per reference VI.1.01.

III.4.02 UNVALIDATED ASSUMPTIONS:

None

Section III – AC Electrical System Model in ETAP for Transient Analysis

III.7 RESULTS

III.7.01 EQUIPMENT DEMAND FACTORS

A summary of the Demand Factors is as follows:

Equipment ID	Minimum Demand Factor	Maximum Demand Factor
1P-015A, 1P-015B, 2P-015A and 2P-015B	35%	104%
P-038A and P-038B	57%	100%
1P-010A, 1P-010B, 2P-010A and 2P-010B	40%	85%
1P-011A, 1P-011B, 2P-011A and 2P-011B	56%	98%
1P-014A, 1P-014B, 2P-014A and 2P-014B	40%	107%
P-032A, P-032B, P-032C, P-032D, P-032E, and P-032F	66%	109%
1W-001A1, 1W-001B1, 1W-001C1, 1W-001D1, 2W-001A1, 2W-001B1, 2W-001C1, and 2W-001D1	25%	100%
XL-10	0%	67%
XL-20	0%	57%
X-17B	0%	35%
XY-09 and XY-10	0%	34%

Section III – AC Electrical System Model in ETAP for Transient Analysis

III.7.02 MOTOR IMPEDANCE MODEL

The motor impedance models were developed for each induction motor on the 480V MCCs greater than 1 HP. The following tables are a summary of the motor impedance models calculated based on ETAP's motor parameter estimation module. Note: The summary table is rounded based on the ETAP output report; however the parameters in the ETAP were automatically updated by ETAP and utilized exact calculated motor parameters as calculated by ETAP.

Equipment ID	Rs	Xs	Xm	Rr		Xr	
				@LR	@FL	@LR	@FL
K-004A	5.99%	10.96%	302.5%	3.30%	3.74%	3.10%	17.49%
K-004B	5.99%	10.96%	302.5%	3.30%	3.74%	3.10%	17.49%
K-005A	5.82%	10.93%	303.5%	4.82%	3.67%	5.07%	14.09%
K-005B	5.82%	10.93%	303.5%	4.82%	3.67%	5.07%	14.09%
P-206A	5.25%	6.43%	240.7%	2.87%	2.92%	4.33%	15.71%
P-206B	5.25%	6.43%	240.7%	2.87%	2.92%	4.33%	15.71%
P-207A	5.25%	6.43%	240.7%	2.87%	2.92%	4.33%	15.71%
P-207B	5.25%	6.43%	240.7%	2.87%	2.92%	4.33%	15.71%
W-012A	4.58%	10.31%	385.5%	3.69%	2.61%	5.12%	16.13%
W-012B	4.58%	10.31%	385.5%	3.69%	2.61%	5.12%	16.13%
W-012C	4.58%	10.31%	385.5%	3.69%	2.61%	5.12%	16.13%
W-012D	4.58%	10.31%	385.5%	3.69%	2.61%	5.12%	16.13%
W-085	4.80%	8.62%	342.9%	3.87%	3.22%	7.35%	8.98%
W-086	4.80%	8.62%	342.9%	3.87%	3.22%	7.35%	8.98%
W-181A1	2.87%	9.58%	186.0%	4.18%	2.83%	7.99%	14.52%
W-181A2	2.87%	9.58%	186.0%	4.18%	2.83%	7.99%	14.52%
W-181A3	2.87%	9.58%	186.0%	4.18%	2.83%	7.99%	14.52%
W-181B1	2.87%	9.58%	186.0%	4.18%	2.83%	7.99%	14.52%
W-181B2	2.87%	9.58%	186.0%	4.18%	2.83%	7.99%	14.52%
W-181B3	2.87%	9.58%	186.0%	4.18%	2.83%	7.99%	14.52%
W-183B	2.98%	2.00%	199.2%	4.34%	5.14%	12.94%	19.72%
W-183C	5.23%	7.73%	196.4%	4.90%	2.61%	7.17%	12.67%
W-184B	5.23%	7.73%	196.4%	4.90%	2.61%	7.17%	12.67%
W-184C	2.98%	2.00%	199.2%	4.34%	5.14%	12.94%	19.72%
W-185A	3.93%	1.03%	169.4%	5.22%	5.40%	14.83%	22.10%
W-185B	3.93%	1.03%	169.4%	5.22%	5.40%	14.83%	22.10%

Section III – AC Electrical System Model in ETAP for Transient Analysis

III.7.03 AC Electrical System Model

The AC electrical system base model to perform transient analysis was created using ETAP that included the safety related system (1A-05, 1A-06, 1B-03, 1B-04, 1B-30, 1B-32, 1B-39, 1B-40, 1B-42, 1B-49, 2A-05, 2A-06, 2B-03, 2B-04, 2B-30, 2B-32, 2B-39, 2B-40, 2B-42, and 2B-49). The base model was created using the methodology described in Section III.2 and utilizes in the technical data from Section III.5. The base model is contained within the follow ETAP computer files:

File Name	File Size	Date
Calc2005-0007.lib	180 KB	06/27/2007 05:50 PM
Calc2005-0007.mdb	14,008 KB	09/05/2007 03:12 PM
Calc2005-0007.oli	4 KB	10/05/2007 09:59 AM
Calc2005-0007.OTI	19 KB	10/05/2007 09:58 AM
Calc2005-0007.scenarios.xml	13 KB	06/01/2007 11:14 AM
Calc2005-0007.macros.xml	4 KB	09/05/2007 06:20 AM

Section III – AC Electrical System Model in ETAP for Transient Analysis

III.8 CONCLUSIONS

The calculation developed the AC Electrical Distribution System model in ETAP include equipment powered by the safety related system (1A-05, 1A-06, 1B-03, 1B-04, 1B-30, 1B-32, 1B-39, 1B-40, 1B-42, 1B-49, 2A-05, 2A-06, 2B-03, 2B-04, 2B-30, 2B-32, 2B-39, 2B-40, 2B-42, and 2B-49). The calculation also developed the worst-case demand factors for both minimum and maximum loading for the equipment contained in the model. The base model created in this calculation will be used to perform electrical analyses that include EDG Transient analysis and Voltage Decay Analysis.

Limitations

The calculation was performed based the AFW modifications (Reference VI.4.09) being completed and the technical parameters associated with the modification are as documented within Input Section III.5 for the following items:

- Motors: P-038A and P-038B (Input Section III.5.02.9)
- Cables: ZE1A65A and ZF2A90A (Input Section III.5.02.3)
- Circuit Breakers 1A52-65 and 2A52-90 (Input Section III.5.02.4)
- Equipment Minimum and Maximum Loading Range (Input Section III.5.03)

The calculation is only applicable if the installed AFW modifications meet the requirements as documented within the Input Sections described above. AR01114775 has been initiated to track the installed modification are bounded by the analyzed condition.

Section IV – EDG Transient Loading Analysis

IV. EDG TRANSIENT LOADING ANALYSIS

IV.1 PURPOSE AND SCOPE

IV.1.01 The purpose of this calculation is to perform a transient loading analysis of the safety related 4160V and 480V system being automatically supplied by the alternate emergency standby power source after a loss of offsite power (LOOP). The calculation is to determine that each emergency diesel generator (G-01, G-02, G-03, and G-04) is capable of sequentially starting and supplying the power requirements of one complete set of safeguards equipment for one unit having a loss of coolant accident (safety injection) and providing sufficient power to place the second unit in a safe shutdown condition. This calculation performs a dynamic transient analysis to demonstrate the emergency diesel generators (EDGs) are capable of sequentially starting the automatic safety related loads, demonstrate motors start and accelerate their driven equipment within sufficient time to support their specified safety function, and demonstrates protective devices will not prematurely trip. The calculation will evaluate the impact of the 480V loss of voltage (LOV) relays and 480V MCC contactor voltage requirements during voltage dips and voltage recovery. The capability of the EDG to restart the loads (if the 480V LOV or 480MCC contactors drop out) will be evaluated. The total duration of time the individual safety related loads will be without power will be identified.

IV.1.02 The scope of this calculation includes the following:

- Determine and verify the various parameters for G-01, G-02, G-03, and G-04, including the governor and exciter models, by comparison of the parameters versus the "Safety Injection Actuation with Loss of Engineered Safeguards AC" tests performed during the Spring 2007 outage.
- Determine the worst-case load sequencing scenario for each EDG and perform transient analyses to determine the response of G-01, G-02, G-03, and G-04.
- Determine the 480V MCC transient voltages during EDG sequential loading and compare them to minimum voltage requirements for the MCC contactors' holding voltage. If contactors drop out, an evaluation is performed to evaluate the impact on the 480V MCC loads on the capability to re-start after the voltage returns above the contactor pickup voltage. In addition, the total time for each safety related MCC load is established for the duration the load will be without power (the time between MCC contactors dropout and pickup).
- Determine the 480V Switchgear transient voltage during sequence loading and compare it to the 480V LOV relays dropout setpoint. If the 480V LOV relays dropout, an evaluation is performed to evaluate the impact on the 480V switchgear loads by establishing the total time for the voltage to recover to the relay's reset setting and identify any affects on load sequencing.
- Evaluate the protective devices' time versus current characteristics to the transient current profile for each dynamically modeled safety related load powered by the EDG.

All transient analyses will be performed using ETAP PowerStation (Reference VI.3.01).

Calculation 2005-0007

IV.2 METHODOLOGY

Note: The methodology utilized in the calculation section is not described within the current licensing basis (CLB) (e.g. FSAR).

IV.2.01 EDG TRANSIENT LOADING ANALYSIS GENERAL

The EDG Transient Loading analysis is being performed to demonstrate that the EDGs (G-01, G-02, G-03 and G-04) are capable of automatically loading the engineering safeguards loads following a loss of offsite power with a loss of coolant accident (LOCA) in one unit and bringing the second unit to safe shutdown. The calculation is also being performed to demonstrate that all safety related loads will be capable of performing their designated safety function by ensuring they automatically load onto the EDG and do not prematurely trip on overcurrent. The following is a general outline of the steps to perform the EDG Transient Loading Analysis:

1. Development of an ETAP Model for the performance of the EDG transient load analysis.
2. EDG tuning and parameter validation
3. Development of scenario's for EDG Transient Loading Analysis
4. Development of study cases for EDG Transient Loading Analysis
5. EDG Transient Loading Analysis in ETAP
6. Effects of Timer Tolerance on EDG Load Sequence
7. Evaluation of 480V MCC Contactors
8. Evaluation of 480V Switchgear LOV Relays
9. Evaluation of Protective Devices on Switchgear

Section IV – EDG Transient Loading Analysis

IV.3 ACCEPTANCE CRITERIA

IV.3.01 The emergency diesel generators shall be able to start and accelerate all required design basis accident loads of the enveloping accident load condition during EDG sequence loading. This ensures that the required safeguards loads are capable of performing their required safety or safety support functions as required to meet PBNP GDC 39. The EDG provides necessary power to cool the core and maintain the containment pressure within design values for a LOCA in addition to supplying sufficient power to shut down the unaffected unit. (Reference VI.8.01 and VI.8.04)

IV.3.02 The 4160V and 480V switchgear circuits' overcurrent protective devices shall not trip at any time during the sequential loading of the EDG. This ensures that the required safeguards motors are capable of performing their required safety functions as require to meet PBNP GDC 39 (Reference VI.8.01)

IV.3.03 The voltage at the 480V switchgear shall ensure the B-train 480V LOV relays do not dropout during EDG loading sequence of the enveloping accident load condition which could impact the load sequence. This ensures that the 480V LOV relays do not dropout which would potentially re-sequence the 480V circuits. Additionally, this ensures that the required safeguards equipment are capable of performing their required safety functions as required to meet PBNP GDC 39 (Reference VI.8.01)

IV.3.04 The motor acceleration time for the SI pump motor shall be less than 8.23 seconds, the residual heat removal shall be less than 1.2 seconds, the SW pumps shall be less than 6.0 seconds, the CAF motors shall be less than 15.1 seconds and the CS pump motor shall be less than 3.3 seconds. The motor accelerations meet the requirements of the FSAR Chapter 14 Accident Analysis (Reference VI.1.15). Note: There are no acceleration time requirements for the CCW and AFW pump motors.

Section IV – EDG Transient Loading Analysis

IV.4 ASSUMPTIONS

Validated Assumptions

IV.4.01 It is assumed that the BHP for the RHR pump motor during ORT 3A and ORT 3B is 125 HP.

Basis: Per ORT 3A and 3B the RHR pumps are aligned for decay heat removal and the low head safety injection flow path is isolated by step 5.3.11 (ORT 3A) and step 5.3.12 (ORT 3B). The procedure aligns the opposite train RHR pump for decay heat removal and establishes flow between 1000 to 1550 gpm. The RHR train being tested is aligned in auto in preparation for the test. During the test both RHR pumps are supplying the water to the reactor through a common flow path. Based on PPCS, the RHR total flow was approximately 1694 gpm for ORT 3A and approximately 1610 gpm for ORT 3B. Therefore, there was approximately 850 gpm flow through each RHR pump during the test and based on calculation 2006-0022 (Reference VI.1.04) the BHP is conservatively estimated to be 125 HP. (Reference VI.4.19, VI.4.20, VI.4.21, and VI.1.04)

IV.4.02 It is assumed that the BHP for the SI pump motor during ORT 3A and ORT 3B is 672 HP.

Basis: Per Attachment G of ORT 3A and 3B, the SI pumps are established to have a flow of 700 to 750 gpm through the full flow test line by adjusting valve 1SI-00829C. Therefore, based on calculation 2006-0022 (Reference VI.1.04) the BHP is conservatively estimated to be 672 HP during the test.

Un-Validated Assumptions

None

Calculation 2005-0007

IV.7 RESULTS

IV.7.01 EDG TUNING AND PARAMETER VALIDATION

The EDG tuning and parameter validation was performed in accordance with the methodology described in Section IV.2.03. The purpose of this section is to tune the generator, governor and exciter parameters to provide performance characteristics in ETAP that match, in the conservative direction, the response of the EDG during the "Safety Injection Actuation with Loss of Engineered Safeguards AC" (ORT 3A and ORT 3B). Therefore, the AC Electrical System model in ETAP was configured to match the completed ORT 3A and 3B safeguard tests (References VI.4.19 and VI.4.20). As stated in methodology section IV.2.03, the generator, exciter and governor were tuned and provide a curve fit for the starting of the RHR pump motor (second load step) in each of the figures below. The curve fit for the SI Pump motor matches for initial voltage dip and is in the same general shape as the ORT safeguard tests signatures for the voltage overshoot, but may not be exact. The voltage overshoot is in the same general shape and occurs later in time in ETAP than the ORT safeguards test signatures as a result of conservatism in the motor impedance model and BHP on the motor within the simulation vs. actual. When reviewing the figures below, it is noted the generator breaker closed at a frequency below nominal in the ORT safeguards test signatures while the model initial frequency is at the generator nominal frequency of 60 Hertz. The initial frequency dip of the SI Pump motor is similar to the ORT safeguard test signatures but at 100% nominal frequency versus the lower value of frequency when the generator output breaker closed in the ORT safeguards tests. This can be seen in the voltage and frequency plots of the completed ORT 3A and 3B safeguard tests.

Section IV – EDG Transient Loading Analysis

IV.8 CONCLUSIONS

IV.8.01 EDG Tuning

The EDGs were tuned in ETAP to match the performance of the EDG's during the "Safety Injection Actuation with Loss of Engineered Safeguards AC" (ORT 3A and ORT 3B). The EDG tuning established the EDG, governor and exciter parameters to provide performance characteristics in ETAP that match, in the conservative direction, the response of the EDG. Therefore, the EDG parameters are considered acceptable to support the EDG Transient loading analysis.

IV.8.02 EDG Transient Loading Analysis in ETAP

The transient analysis determined that each EDG is capable of sequentially starting and accelerating all the required design basis loads of the enveloping accident load conditions. In addition, the transient analysis demonstrated that all safety related motors were capable of starting throughout the worst-case sequence of events including the CS motor which may start anytime after a nominal 10.25 seconds. Acceptance Criteria IV.3.01 has been satisfied.

IV.8.03 Motor Acceleration Times and Time Tolerances

The transient analysis shows that the SI, RHR, SW, CAF and CS were maintained within the required motor starting times. A comparison of the acceleration times of the induction motors and the minimum time between consecutive sequenced loads determined that no additional analysis is required because there is no potential for overlap between the SI, RHR, AFW and SW motors. There is a potential for overlapping load sequences between the start of the first and second CAF motor but overlap occurred within the transient analysis and demonstrated that both CAF motors will successfully accelerate their driven equipment during the overlap of the two CAF motors. Acceptance Criteria IV.3.04 has been satisfied.

IV.8.04 480V MCC Contactors and Loads

The voltage profiles at the safety related 480V MCCs were evaluated and found to demonstrate the sequenced MCC loads will successfully start and accelerate their driven equipment under each of the loading conditions including the overlapping load condition and the worst case affects of starting the CS motor and MCC process initiated loads during EDG sequential loading. The MCC loads may have short power interruptions as a result of initial contactor pickup or the contactors dropping out during the load sequence. However, this will not impact the EDG operation since no loads directly support the operation of the EDG (e.g. load required to operate to keep EDG running). Slight interruptions of the EDG fuel oil transfer pump, EDG room exhaust fans or EDG Radiator Cooling Fans will not prevent the EDG from performing its safety function since power is restored to the MCC loads to re-energize the loads as stated in section IV.7.04. Therefore, Acceptance Criteria IV.3.01 has been satisfied.

The calculation shows that MCC's 1B-32, 1B-42, 2B-32 and 2B-42 will have a delay in establishing power and a potential interruption of power during the load sequence which supply power to several MOV's required to support operation of the RHR, CS and SW systems. The evaluation of the timing requirements in Calculation 97-0041 need to incorporate the additional time delay in the MOV's to support the timing requirements of the Accident Analysis. AR01105237 has been initiated to document the condition and update calculation 97-0041 with the information.

Section IV – EDG Transient Loading Analysis

IV.8.05 480V Switchgear and LOV Relays

The voltage profiles at the safety related 480V switchgear loads were evaluated and found to demonstrate the sequenced loads will successfully start and accelerate their driven equipment under each of the loading conditions including the overlapping load condition of the two CAFs and the worst case affects of starting the CS motor and MCC process initiated loads during EDG sequential loading. Acceptance Criteria IV.3.01 has been satisfied.

An evaluation of the B-train LOV scheme was performed because the LOV scheme will initiate load shedding and block automatic load sequencing on dropout of the relays until sufficient voltage recovers on the buses to reset the relays. This does not impact the A-train because the LOV scheme is blocked once the EDG output breakers are closed. The results show in all cases except DG Case 5-1 and DG Case 5-2 the B-train 480V LOV relays will not dropout or impact the 480V Switchgear loads and satisfied Acceptance Criteria IV.3.03. However, DG Case 5-2 determined the 480V LOV relays will actuate during the simultaneous start of two SW motors. This is considered unacceptable for 2B-04, because this would initiate the 480V load shedding scheme on the bus which will require all the loads to re-sequence on the bus. Therefore, Acceptance Criteria IV.3.03 is not maintained when an A-train EDG (G-01 and G-02) is supplying the system when the 480V B03/B04 cross-tie is in service for 2B-03 and 2B-04. This condition requires a limitation to prevent the simultaneous start of two SW motors. AR01114773 has been initiated to document the condition and incorporate the limitation into plant procedures.

IV.8.06 Protective Devices on the Switchgear

The evaluation of the overcurrent protective device versus the current profile of the circuits connected to the 4160V and 480V switchgear determined that no overcurrent protective devices actuate during the EDG loading sequence. Acceptance Criteria IV.3.02 has been satisfied.

IV.8.07 Limitations:

The calculation was performed based the following operating limitation when the 480V B03/B04 cross-tie is in-service and a single EDG is supply both units A-train and B-train buses. The following are the operating restrictions during this plant operating condition:

- 480V bus tie in-service 2B-03 supplied by 2B-04: 2P-011A and P-032F are "off" (pull-out) when a single EDG is supplying both units B-Train.
- 480V bus tie in-service 2B-04 supplied by 2B-03: 2P-011B, P-032D and P-032E are "off" (pull-out) when a single EDG is supplying both units A-Train.
- 480V bus tie in-service 1B-03 supplied by 1B-04: 1P-011A, P-032A and P-032B are "off" (pull-out) when a single EDG is supplying both units B-Train.
- 480V bus tie in-service 1B-04 supplied by 1B-03: 1P-011B and P-032C are "off" (pull-out) when a single EDG is supplying both units A-Train.

The calculation is only applicable if the above operating limitations are implemented when the plant is placed in the above operating conditions. AR01114773 has been initiated to track implementation of the operating restrictions in plant procedures.

In addition, overcurrent protective device settings to be installed for the AFW modification must ensure they do not trip for the composite motor current profile in Attachment D2 within the EC1565 and 1566. AR01114775 has been initiated to track

Section IV – EDG Transient Loading Analysis

that modifications EC1565 and 1566 ensure the AFW overcurrent protection will not trip for the worst-case composite motor current profile shown in Attachment D2.

5.0 ASSUMPTIONS

5.1 It is assumed the new W-013B1 and W-013B2 is consistent with motor data provided in Reference 6.4 (Input 4.7).

Basis: The motor data provided by Homewood Energy is the proposed motor to be purchased to replace the existing W-013B1 and W-013B2 motors as part of the AST modification. This data will be representative of the installed 15 HP motor. Slight changes in actual purchased motor data for W-013B1 and W-013B2 will have a negligible impact on the EDG transient response. Note: Any changes to the motor data will be evaluated as part of the detailed design of the AST modification.

5.2 It is assumed that locked rotor power factor for the new W-013B1 and W-013B2 is 51%.

Basis: The typical locked rotor power factor in Ref. 6.1 for a 15 HP is 55% based on manufacturer motor data from Baldor/Reliance. Slight variations in locked rotor power factor will have minimal impact on the affects of the motor impedance model based on evaluation within ETAP. However, ETAP Parameter Estimation module were unable to identify a solution within the inputs in Section 4.7 and locked rotor power factor of 55%. Therefore, this required the locked rotor power factor to be revised to 51%. The change in the locked rotor power factor has a negligible impact on the motor impedance parameters calculated by ETAP. Reducing the locked rotor power factor for the motors will result in an increase in reactive loading during motor starting. This results in a slightly weaker motor (slightly lower motor torque) which will provide conservative characteristics based on reducing the locked rotor power factor in ETAP while retaining other parameters constant. Since the remaining parameters remain constant, this has a negligible impact on the calculated motor parameters. Therefore, the motor impedance models are determined to be acceptable utilizing a locked rotor power factor of 51%.

7.0 ANALYSIS

The EDG transient load analysis is performed utilizing the methodology described in Section 3.2. This engineering evaluation will determine (1) determine the EDGs are capable of sequentially starting and accelerating safety related loads during accident conditions, (2) that adequate voltage is available to downstream 480V switchgear buses to prevent actuation of the B-train 480V LOV relays, and (3) determine motor acceleration times to meet appropriate acceptance criteria. The following steps are utilized in the performance of this evaluation:

7.1 The AC Electrical Distribution System model was developed in calculation 2005-0007 and revised as discussed in Section 3.2.1. Calculation 2005-0007 and Section 4.0 developed the required inputs to perform the EDG transient loading analysis. This model is utilized to perform all the required analysis to determine the EDG transient load analysis, worst-case voltage and frequency profiles of the EDG, worst case voltage profiles at the 480V switchgear, worst-case motor acceleration times during load sequencing. The ETAP motor parameter estimation reports for W-013B1, W-013B2, W-014A and W-014B are contained in Attachment 4. The computer files and inputs for the model that are revised by this engineering evaluation are as follows:

File Name	File Size	Date
Calc2005-0007.lib	180 KB	06/27/2007 05:50 PM
Calc2005-0007.mdb	14,172 KB	06/11/2009 10:09 AM
Calc2005-0007.oli	4 KB	06/11/2009 09:21 AM
Calc2005-0007.OTI	19 KB	06/11/2009 10:09 AM
Calc2005-0007.scenarios.xml	16 KB	06/07/2009 05:40 AM
Calc2005-0007.macros.xml	6 KB	06/09/2009 03:38 PM

7.2 This section utilizes ETAP PowerStation computer software to perform the required EDG transient load analyses utilizing the transient analysis module. The computer software is a Level A application and meets the requirements of procedure NAP-501 "Software Quality Assurance Program" (grandfathered from previous procedure FP-IT-SQA-01).

7.3 The plant operating conditions are established within the AC Electrical Distribution System model in ETAP based on the methodology Sections 3.2.4. The plant operating conditions are labeled as DG Case 1, DG Case 2, DG Case 3, and DG Case 4.

7.4 The following steps will determine the transient loading response for the EDGs, 4160V System and 480V system to ensure that the EDGs are capable of sequentially loading all required safeguards equipment during a LOOP event (with or without a LOCA). The steps must be performed sequentially. (Methodology Section 3.2.5)

7.4.1 The model is placed in the configuration status (plant operating condition) in ETAP for the EDG and condition to be evaluated. DG Case 1 through DG Case 4 provides the enveloping loading conditions for the EDGs.

7.4.2 The EDG transient loading analysis is determined by ETAP's Transient program. The appropriate study case is developed in methodology section 3.2.4 and identifies the options necessary to perform the analysis. These study cases are labeled as DG Case 1-2, DG Case 2-2, DG Case 2-3, DG Case 3-2, DG Case 4-2, and DG Case 4-3.

7.4.3 The SI, RHR, SW, CAF, CCW, and CS motor impedance models utilize a shunt impedance to support the motor's dynamic impedance model. Therefore, the time at which the shunt impedance is turned off is established and placed within the study case once the appropriate slip in section III.5.02.9 of Calculation 2005-0007 is reached. The following are the established times to place into the study case (extracted from Section IV.6.05.3 of Calculation 2005-0007, Ref. 6.1):

Case 1 Study Cases:

DG Case 1-2				
Time Sequence	Event ID	Equipment	Event Actions	Motor Starting Category
T = 4.0 seconds	T-SI-L	SW-1P-015B	Open	N/A
T = 1.6 seconds	T-CCW-L	SW-2P-011B	Open	N/A
T = 6.4 seconds	T-RHR-L	SW-1P-010B	Open	N/A
T = 11.9 seconds	T-CS-L	SW-1P-014B	Open	N/A
T = 17.3 seconds	T-SW1-L	SW-P-032C	Open	N/A
T = 22.2 seconds	T-SW2-L	SW-P-032D	Open	N/A
T = 27.5 seconds	T-SW3-L	SW-P-032E	Open	N/A
T = 52.1 seconds	T-CAF1-L	SW-1W-001C1	Open	N/A
T = 60.3 seconds	T-CAF2-L	SW-1W-001D1	Open	N/A

Case 2 Study Cases

DG Case 2-2				
Time Sequence	Event ID	Equipment	Event Actions	Motor Starting Category
T = 4.6 seconds	T-SI-L	SW-1P-015A	Open	N/A
T = 2.7 seconds	T-CCW-L	SW-2P-011A	Open	N/A
T = 6.5 seconds	T-RHR-L	SW-1P-010A	Open	N/A
T = 12.3 seconds	T-CS-L	SW-1P-014A	Open	N/A
T = 17.3 seconds	T-SW1-L	SW-P-032A	Open	N/A
T = 22.4 seconds	T-SW2-L	SW-P-032B	Open	N/A
T = 27.6 seconds	T-SW3-L	SW-P-032F	Open	N/A
T = 53.1 seconds	T-CAF1-L	SW-1W-001A1	Open	N/A
T = 60.2 seconds	T-CAF2-L	SW-1W-001B1	Open	N/A

DG Case 2-3				
Time Sequence	Event ID	Equipment	Event Actions	Motor Starting Category
T = 4.4 seconds	T-SI-L	SW-1P-015A	Open	N/A
T = 2.3 seconds	T-CCW-L	SW-2P-011A	Open	N/A
T = 6.5 seconds	T-RHR-L	SW-1P-010A	Open	N/A
T = 17.3 seconds	T-SW1-L	SW-P-032A	Open	N/A
T = 22.4 seconds	T-SW2-L	SW-P-032B	Open	N/A
T = 28.6 seconds	T-SW3-L	SW-P-032F	Open	N/A
T = 28.6 seconds	T-CS-L	SW-1P-014A	Open	N/A
T = 53.1 seconds	T-CAF1-L	SW-1W-001A1	Open	N/A
T = 60.2 seconds	T-CAF2-L	SW-1W-001B1	Open	N/A

Case 3 Study Cases

DG Case 3-2				
Time Sequence	Event ID	Equipment	Event Actions	Motor Starting Category
T = 4.4 seconds	T-SI-L	SW-2P-015A	Open	N/A
T = 2.2 seconds	T-CCW-L	SW-1P-011A	Open	N/A
T = 6.5 seconds	T-RHR-L	SW-2P-010A	Open	N/A
T = 12.3 seconds	T-CS-L	SW-2P-014A	Open	N/A
T = 17.3 seconds	T-SW1-L	SW-P-032A	Open	N/A
T = 22.4 seconds	T-SW2-L	SW-P-032B	Open	N/A
T = 27.6 seconds	T-SW3-L	SW-P-032F	Open	N/A
T = 53.6 seconds	T-CAF1-L	SW-2W-001A1	Open	N/A
T = 59.9 seconds	T-CAF2-L	SW-2W-001B1	Open	N/A

Case 4 Study Cases

DG Case 4-2				
Time Sequence	Event ID	Equipment	Event Actions	Motor Starting Category
T = 4.1 seconds	T-SI-L	SW-2P-015B	Open	N/A
T = 1.5 seconds	T-CCW-L	SW-1P-011B	Open	N/A
T = 6.4 seconds	T-RHR-L	SW-2P-010B	Open	N/A
T = 11.9 seconds	T-CS-L	SW-2P-014B	Open	N/A
T = 17.3 seconds	T-SW1-L	SW-P-032C	Open	N/A
T = 22.1 seconds	T-SW2-L	SW-P-032D	Open	N/A
T = 27.5 seconds	T-SW3-L	SW-P-032E	Open	N/A
T = 52.7 seconds	T-CAF1-L	SW-2W-001C1	Open	N/A
T = 59.8 seconds	T-CAF2-L	SW-2W-001D1	Open	N/A

DG Case 4-3				
Time Sequence	Event ID	Equipment	Event Actions	Motor Starting Category
T = 4.1 seconds	T-SI-L	SW-2P-015B	Open	N/A
T = 1.5 seconds	T-CCW-L	SW-1P-011B	Open	N/A
T = 6.4 seconds	T-RHR-L	SW-2P-010B	Open	N/A
T = 17.3 seconds	T-SW1-L	SW-P-032C	Open	N/A
T = 22.1 seconds	T-SW2-L	SW-P-032D	Open	N/A
T = 27.7 seconds	T-SW3-L	SW-P-032E	Open	N/A
T = 27.6 seconds	T-CS-L	SW-2P-014B	Open	N/A
T = 52.7 seconds	T-CAF1-L	SW-2W-001C1	Open	N/A
T = 59.8 seconds	T-CAF2-L	SW-2W-001D1	Open	N/A

7.4.4 The EDG transient loading analysis is performed utilizing ETAP by running the transient analysis program for each study case, updated for section 7.4.3. The EDG transient loading analysis will ensure the EDG and the safety related equipment are capable of performing their function after a LOOP event.

7.4.5 The results are contained in Attachments 5 to 10.

8.0 EVALUATION AND RESULTS

8.1 EDG Transient Loading Analysis in ETAP

The EDG transient loading analysis was performed for each plant operating condition and associated study cases in Section 3.2.4 to ensure that the EDG and safety related equipment are capable of performing the safety or safety support function during a LOOP event (with or without a LOCA).

The following are the results of the EDG transient loading analysis. A total of 6 transient loading analyses were performed to demonstrate the capability of the EDG and the safety related equipment based on the impacts of the AFW modification and AST modification. For each of the transient load runs there is a figure in Attachment 1 of the generator voltage and frequency profiles and is also compared to the results of Calculation 2005-0007 (Ref. 6.1) to show the delta between this engineering evaluation and calculation 2005-0007.

The EDG transient loading analyses is contained in Attachments 5 to 10. Figures 8-1 through 8-30 in Attachment 1 and 2 provides a summary of the results by providing the voltage and frequency profile for each run/study case. The results show the EDG's are capable of sequentially loading the required LOOP loads (with or without a LOCA) under all worst-case loading conditions. In each case, the voltage and frequency recover to acceptable levels (within +/-5% of 97.5% of nominal voltage and within +/-0.2% of nominal 60Hz) prior to starting of the subsequent sequenced motor. In addition, all safety related motors were capable of starting and coming up to full speed while supplied by the EDG. The following is a summary of the voltage and frequency response of the EDG transient loading analysis:

Generator Voltage Profile

A summary of the generator voltage profiles are provided in figures 8-1 through 8-12 in Attachment 1. The generator voltage profiles provided in Attachment 1 provide the new generator voltage profile as calculated in this engineering evaluation and compared it to same profile in Calculation 2005-0007 to establish the differences as a result of the AFW modification and AST modification. The previous worst-case generator voltage occurred at $t=0^+$ when SI and CCW simultaneously started and resulted in the initial generator voltage dip to be approximately 54% for both G-01 and G-02 in Case 2-2 and 3-2 scenarios. The new worst-case generator voltage occurs at $t=0^+$ when SI, CCW and AFW simultaneously started and results in the initial generator voltage dip to be approximately 48% for both G-01 and G-02 in Case 2 scenario when the AFW motor is in the non-LOCA/SI unit.

An additional, scenario was evaluated at t=25.75 seconds when SW and CS are considered to simultaneously start and this resulted in a generator voltage dip of approximately 60% for both G-01 and G-02 in Case 2-3 scenario. The new generator voltage occurs at t=25.75 seconds when SW and CS are considered to start in the LOCA/SI Unit and AFW in non-LOCA/SI Unit simultaneously started and results in a generator voltage dip of approximately 52% for both G-01 and G-02 in Case 2-3 scenario when the AFW motor is in the non-LOCA/SI unit.

However in all cases, the generators were capable of recovering back to nominal voltage while starting and accelerating the motors. The EDG's were capable of starting and accelerating the safety related motor's while recovering back to nominal voltage.

The previous worst-case voltage overshoot of G-01 and G-02 occurred after the SW and CS motor start and complete their acceleration (DG Case 2-3). The voltage reaches approximately 130.5% with all other voltage overshoots being lower. The new worst-case voltage overshoot of G-01 and G-02 occurs after the SW, CS, and AFW motor start and complete their acceleration in DG Case 2-3. The voltage reaches approximately 132.2% with all other voltage overshoots being lower. The momentary voltage overshoots are considered acceptable because the voltage on the system are at these values for less than approximately 2-3 seconds after which the voltage reduces back to normal. The short time duration of the voltage overshoot will not impact the operation of the equipment supplied by the EDG's because this is not sufficient time to negatively impact life of the motor or will not cause motor insulation breakdown as shown by periodic megger testing. Additionally, PBNP performs routine preventative maintenance of the safety related equipment which would identify any long term impacts on the equipment as a result of the higher voltage.

The voltage profiles of G-03 and G-04 (Cases 1 and 4) are completely enveloped by the voltage profiles of G-01 and G-02 (Cases 2 and 3). The previous worst-case generator voltage occurred at $t=0^+$ when SI and CCW simultaneously started and resulted in the initial generator voltage dip to be approximately 84% for both G-03 and G-04 in Case 1-2 and 4-2 scenarios.

The new worst-case generator voltage occurs at $t=0^+$ when SI, CCW and AFW simultaneously started and results in the initial generator voltage dip to be approximately 83% for both G-03 and G-04 in DG Case 4-2 scenario when the AFW motor is in the non-LOCA/SI unit.

An additional, scenario was evaluated at t=25.75 seconds when SW and CS are considered to simultaneously start and this resulted in a generator voltage dip of approximately 92% for both G-03 and G-04 in Case 4-3 scenario. The new generator voltage occurs at t=25.75 seconds when SW and CS are considered to start in the LOCA/SI Unit and AFW in non-LOCA/SI Unit simultaneously started and results in a generator voltage dip of approximately 89% for both G-03 and G-04 in Case 4-3 scenario when the AFW motor is in the non-LOCA/SI unit.

The EDG's were capable of starting and accelerating the safety related motor's while recovering back to nominal voltage. The worst-case maximum voltage overshoot remained below 100.5% nominal voltage (Note: the EDG operating point is set at 4050V or 97.4%).

Voltage Regulator Design and Performance

For voltage regulation, G-01 and G-02 EDGs utilize an EMD/Basler Mag Amp Voltage Regulator with static exciter.

The static exciter is a three-phase, full-wave magnetic amplifier that supplies DC Excitation current to the generator field. The static exciter amplifies the signal from the voltage regulator to the power level required for proper generator field excitation. The exciter assembly consists of six individual reactors, rectifying diodes, and a magnetic amplifier.

Power input to the main windings of the exciter is supplied from a three-phase potential transformer. In addition, power current transformers are also used to prevent output voltage collapse and provide rapid voltage recovery when large motor loads are started. The power current transformers are critical to the design because the input to the three-phase, full wave magnetic amplifier is a vector sum of the exciter potential transformer input and the power current transformer inputs. During a large motor start, the input from the exciter potential transformer would reduce as output voltage declines; however the input from power current transformers would increase as a result of large inrush current for motor starts. The power current transformers are designed to provide a larger impact than the exciter potential transformer. Therefore, the exciter field will have sufficient voltage to recover the EDG output voltage. The rapid voltage recovery for the acceleration of motors and load are accomplished because of the discussion above related to the Power Current Transformers. (References 6.7, 6.8, 6.9, and 6.10)

A review of the voltage regulator design per references 6.7, 6.8, and 6.9 show that the voltage regulator will not shutdown or otherwise cease to operate during extreme transient demands (e.g., motor starting). This is because the static exciter derives its excitation source from the exciter potential transformers and control power transformers (as mentioned above); which is in excess of that required for full load operation. There are no voltage or current limiting devices that will prohibit the operation of the exciter. A current limit design feature is included to protect the generator from overload but does not prohibit operation of exciter.

Proper voltage regulation is provided by a combination of a reverse acting control signal (signal amplifier) that essentially reigns in the excess/available excitation and a forward acting bias signal that is set for 115% full load rated generator field current. The bias signal is stationary and the reverse acting control signal is what controls excitation via the voltage regulator. An increase in the voltage regulator control signal *reduces* excitation. A decrease in control signal, results in an increase in excitation (up to the bias setpoint level of 115%). Therefore, during a motor starting transient, the voltage regulator control signal will decrease to a minimum to allow the magnetic amplifier to rapidly increase, supporting the excitation necessary to mitigate voltage drop and provide rapid voltage recovery.

Therefore, the EDGs will be capable of recovering the EDG output voltage as a result of the large voltage due to a large motor load based on the design of the voltage regulator / excitation system as long as the EDG is maintained within the maximum allowable dead load pickup capability. The voltage regulator/exciter will produce the maximum excitation as necessary to support motor starting; and has no discrete point at which it will shutdown.

In addition, G-01 and G02 has maximum dead load pickup capability of 12.5MVA. This is the maximum impact load (e.g starting MVA) the EDG can successfully start and recover (Ref. 6.10). A review of the results in Attachments 5 through 10 of this evaluation, show that the maximum impact load placed onto G-01 or G-02 is less than 7MVA. This is well within the maximum capability of the EDG's.

Summary

Engineering Evaluation EC13025 adequately addresses the impact of AR01139357 and this engineering evaluation does not impact the methodology, results or conclusions of EC13025. Therefore, a voltage dip of 48% or the effects of EC13025 (Additional 3% voltage drop) will not impact the ability of the voltage regulator to recover voltage after a motor starts on the EDG's based on the discussion presented above since the maximum impact load is within the capability of the EDGs and the excitation system will provide sufficient capability to restore EDG output voltage,. Therefore, the EDG's will be capable of performing their safety function to start and accelerate all required design basis loads (Acceptance Criteria IV.3.01 of Calculation 2005-0007).

The AFW modification and AST modifications have a relatively minor impact on the transient response of the EDGs. Based on a review of the figures in Attachment 1, it has a relatively similar response to Calculation 2005-0007 and the modifications did not impact the EDG's capability to perform their designated safety function. Therefore, the EDG's are capable of starting and accelerating all automatically started loads onto the EDGs.

Generator Frequency Profile

A summary of the generator frequency profiles are provided in figures 8-2, 8-4, 8-6, 8-10, and 8-12 in Attachment 1. A review of Calculation 2005-0007 shows the frequency profiles for G-01, G-02, G-03 and G-04 show a range of 58.5 Hz to 60.9 Hz. In each case the frequency recovers to sufficient levels (within +/-0.2% of nominal 60Hz) prior to starting of the next sequenced motor. The new analysis shows the frequency profiles for G-01, G-02, G-03 and G-04 remain bounded within the range of 58.5 Hz to 60.9 Hz in previous Calculation 2005-0007. In the cases analyzed within this engineering evaluation, the worst-case frequency dip increased by approximately 0.2 Hz.

In summary, the results (figures 8-1 through 8-2 in Attachment 1) of the engineering evaluation show that the EDG's are capable of starting and accelerating all the required safety related loads following a LOOP (with and without a LOCA). Therefore Acceptance Criteria IV.3.01 of Calculation 2005-0007 remains satisfied after completion of the AFW modification and AST modification.

8.2 Motor Acceleration Time Review

A summary of the acceleration times for each individual motor for the plant operating scenario's and associated study cases analyzed in this engineering evaluation are provided below. The results show that the acceleration time of the motors meet the requirements in section 3.2.8 which are based on Acceptance Criteria IV.3.04 in Calculation 2005-0007. The AFW modification and AST modification had a slight impact on the acceleration of the motors as a result of AFW pumps starts at $T=0^+$ and T=25.75 seconds. However, the slight increase in acceleration times were still within the required acceptance criteria to support Chapter 14 accident analysis. Therefore, Acceptance Criteria IV.03.04 of Calculation 2005-0007 and Section 3.2.8 would remain satisfied after completion of the AFW modification and AST modification.

Equipment ID	DG Case 1-2	DG Case 2-2	DG Case 2-3	DG Case 3-2	DG Case 4-2	DG Case 4-3	Longest Acceleration Time	Calculation 2005-0007 Longest Acceleration Time	Acceptance Criteria
1P-015A	N/A	4.54	4.36	N/A	N/A	N/A	4.54	4.24	<8.23
1P-015B	3.98	N/A	N/A	N/A	N/A	N/A			
2P-015A	N/A	N/A	N/A	4.34	N/A	N/A			
2P-015B	N/A	N/A	N/A	N/A	4.02	3.98			
1P-053	2.78	3.84	3.11	N/A	N/A	N/A	3.84	2.72	<5.0
2P-053	N/A	N/A	N/A	2.80	2.94	2.79			
1P-010A	N/A	0.90	0.90	N/A	N/A	N/A	0.94	0.94	<1.2
1P-010B	0.80	N/A	N/A	N/A	N/A	N/A			
2P-010A	N/A	N/A	N/A	0.94	N/A	N/A			
2P-010B	N/A	N/A	N/A	N/A	0.80	0.80			
1P-011A	N/A	N/A	N/A	2.10	N/A	N/A	2.58	2.09	N/A
1P-011B	N/A	N/A	N/A	N/A	1.46	1.38			

Equipment ID	DG Case 1-2	DG Case 2-2	DG Case 2-3	DG Case 3-2	DG Case 4-2	DG Case 4-3	Longest Acceleration Time	Calculation 2005-0007 Longest Acceleration Time	Acceptance Criteria
2P-011A	N/A	2.58	2.14	N/A	N/A	N/A			
2P-011B	1.38	N/A	N/A	N/A	N/A	N/A			
1P-014A	N/A	1.72	2.76	N/A	N/A	N/A	2.76	2.15	<3.3
1P-014B	1.36	N/A	N/A	N/A	N/A	N/A			
2P-014A	N/A	N/A	N/A	1.74	N/A	N/A			
2P-014B	N/A	N/A	N/A	N/A	1.34	2.09			
1W-001A1	N/A	14.22	14.22	N/A	N/A	N/A	14.72	14.64	<15.1
1W-001B1	N/A	13.85	13.83	N/A	N/A	N/A			
1W-001C1	13.26	N/A	N/A	N/A	N/A	N/A			
1W-001D1	14.09	N/A	N/A	N/A	N/A	N/A			
2W-001A1	N/A	N/A	N/A	14.72	N/A	N/A			
2W-001B1	N/A	N/A	N/A	13.59	N/A	N/A			
2W-001C1	N/A	N/A	N/A	N/A	14.00	14.00			
2W-001D1	N/A	N/A	N/A	N/A	13.59	13.57			
P-032A	N/A	1.76	1.72	1.72	N/A	N/A	2.76	2.20	<6.0
P-032B	N/A	1.82	1.80	1.80	N/A	N/A			
P-032C	1.74	N/A	N/A	N/A	1.76	1.74			
P-032D	1.84	N/A	N/A	N/A	1.58	1.68			
P-032E	1.72	N/A	N/A	N/A	1.87	1.91			
P-032F	N/A	1.78	2.76	1.78	N/A	N/A			

8.3 Evaluation of Switchgear Voltage Profile and 480V LOV Relays

A summary of the switchgear voltage profiles are provided in figures 8-13 through 8-30 in Attachment 2. The switchgear voltage profiles in Attachment 2 provide the new switchgear voltage profile as calculated in this engineering evaluation and compared it to same profile in Calculation 2005-0007 to establish the differences as a result of the AFW modification and AST modification. The results show that all 480V switchgear motors will start and accelerate their driven equipment and meet Acceptance Criteria IV.3.01 of Calculation 2005-0007. The 480V LOV relays meet the acceptance criteria IV.3.03 within Calculation 2005-0007 based on the summary results in Attachment 2. The results show that the AFW modification and AST modification have a minor impact on the voltage response of the system. Therefore, Acceptance Criteria IV.3.01 and IV.3.03 of Calculation 2005-0007 would remain satisfied after completion of the AFW modification and AST modification.

9.0 CONCLUSIONS

In Conclusion, the AFW modification and AST modification have a overall minor impact on the EDG Transient analysis and all equipment would remain capable of performing their specified safety function for support the design basis of the plant.

ENCLOSURE 8

NEXTERA ENERGY POINT BEACH, LLC
POINT BEACH NUCLEAR PLANT, UNITS 1 AND 2

LICENSE AMENDMENT REQUEST 261
EXTENDED POWER UPRATE
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION

ADDITIONAL INFORMATION - QUESTION 6 RESPONSE
EDG FUEL OIL SYSTEM CALCULATION

15 pages follow

Purpose:

The purpose of this calculation is to:

Document the basis for the level switch settings (including applicable uncertainty) for the:

- EDG Day Tanks (T-031A, T-031B, T-176A, and T-176B)
- G01/G02 Skid Mounted Fuel Oil Tanks
- Fuel Oil Storage Tanks (T-175A and T-175B)

Document the process limit for the minimum indicated level for the Fuel Oil Storage Tanks (T-175A and T-175B).

Establish Inservice Testing acceptance criteria for the Fuel Oil Transfer Pumps (P-206A, P-206B, P-207A, and P-207B) flow capability to their associated day tanks (T-031A, T-031B, T-176A, and T-176B).

Generate a curve showing the indicated level by sight glass versus the gallons of usable fuel in the G-02 EDG Skid Mounted Fuel Oil Tank. The curve will also depict the fuel oil transfer level switch set points.

Generate a curve showing the % indicated level versus the total tank volume in the Fuel Oil Storage Tanks (T-175A/B).

Validate that the Technical Specification fuel oil required value of 11,000 gallons satisfies the 48 hour run of one EDG of each train, at rated load.

Validate that the seven day operation of one EDG at required loads with tanks T-175A and T-175B cross tied can be met.

Validate that the two hour operation of one EDG at rated load can be met by the EDG Day Tanks (T-031A, T-031B, T-176A and T-176B) and the G-01/G-02 Skid Mounted Tanks.

Evaluate fuel oil storage capacity in tanks T-175A, T-175B, T-032A, T-032B and T-030 to support the following Appendix R operation:

- Two EDGs (G-01, G-02, G-03 or G-04) or the Gas Turbine (G-05) for the 72 hr duration of the Appendix R event
- Diesel Engine for Fire Pump P-035B (P-035B-B) operation for 8 hours

Revision 5 includes the following changes: (1) Removes the 10% margin identified for the T-176A and T-176B day tank capacity determination. This margin was provided for initial tank sizing and is not applicable to subsequent capacity evaluations. (2) Clarifies the basis for the High Heating Value to be used for Ultra Low Sulfur Diesel and recalculates fuel consumption rate at PBNP fuel conditions to address A/R 01114489. (3) Removes the conservatism in the temperature correction used for the fuel oil consumption rate determination.

Background:

During a design basis accident or any time offsite power is lost, the EDG Fuel Oil System provides a fuel supply to the EDG's to support the combustion process. An adequate supply of fuel oil is required to allow the EDGs to meet the power requirements for the accident and/or safe-shutdown loads. Fuel oil stored in the following tanks is available to the EDGs:

- Fuel Oil Storage Tank T-175A – This tank is primarily used to support operation of EDG G-01 and G-02. Fuel is pumped from T-175A to tanks T-031A and T-031B via fuel oil transfer pumps P-206A or P-207A.
- Fuel Oil Storage Tank T-175B – This tank is primarily used to support operation of EDG G-03 and G-04. Fuel is pumped from T-175B to tanks T-176A and T-176B via fuel oil transfer pumps P-206B or P-207B.
- EDG G-01 Day Tank T-031A - This tank supports operation of EDG G-01. Fuel is pumped from T-031A to the G-01 skid mounted fuel oil tank via skid mounted fuel oil transfer pumps G01-P-FTC1 and G01-P-FTC2.
- EDG G-02 Day Tank T-031B - This tank supports operation of EDG G-02. Fuel is pumped from T-031B to the G-02 skid mounted fuel oil tank via skid mounted fuel oil transfer pumps G02-P-FTC1 and G02-P-FTC2.
- EDG G-03 Day Tank T-176A - This tank supports operation of EDG G-03. Fuel is supplied from T-176A to G-03 via engine mounted fuel oil pumps P-208A and P-209A.
- EDG G-04 Day Tank T-176B - This tank supports operation of EDG G-04. Fuel is supplied from T-176B to G-04 via engine mounted fuel oil pumps P-208B and P-209B.
- EDG G-01 Skid Mounted Fuel Oil Tank - This tank supports operation of EDG G-01. Fuel is pumped to G-01 via engine mounted fuel oil pumps P-240A and P-240B.
- EDG G-02 Skid Mounted Fuel Oil Tank - This tank supports operation of EDG G-02. Fuel is pumped to G-02 via engine mounted fuel oil pumps P-241A and P-241B.

Cross-ties between the discharge of the T-175A/B transfer pumps and the day tanks allow the inventory of T-175A and T-175B to be used to support any of the four EDG's.

For Appendix R compliance, electrical loads are supported by two of the EDGs (G-01, G-02, G-03 or G-04) or the Gas Turbine (G-05). Fuel oil is supplied to the Gas Turbine from tanks T-032A and T-032B through pump P-105. Fire Pump Diesel Engine P-035B-E is supplied fuel oil from tank T-030.

Revision 0 of this calculation established the basis for settings of level switches for Tanks T-175A, T-175B, T-176A and T-176B. Revisions 1 and 2 of this calculation added physical dimensions from the bottom of T-175A and T-175B for the high and low settings of the level switch and added a discussion of level instrument uncertainty.

Revision 4 merges the Fuel Oil System evaluations (N-94-142 Rev. 3, 6704.001-C-061 Rev. 1, 6704.001-C-063 Rev. 2, 2001-0010 Rev. 1, N-90-079 Rev. 1) for all four EDGs into a single calculation and expands the scope to address the determination of the minimum useable volume in the tanks based on NPSH requirements and vortex criteria. It will also address fuel oil requirements for Appendix R compliance.

Although the G-01 skid mounted fuel oil tank currently has no level glass, it is anticipated that a modification similar to that on G-02 may be installed in the future. Provided that the modification is similar to that installed on G-02, and the gage glass is calibrated similarly (i.e. with reference to the floor slab surface), then the results of this calculation may be applied to the G-01 skid mounted fuel oil tank as well.

AR 01043496 addresses operating experience with determination of fuel oil storage capacity where the diesel loading profile was not considered in determining the fuel consumption. This calculation uses the 2000 hr engine rating for G-01 and G-02 and 195 hr engine ratings for G-03 and G-04 to determine fuel consumption. See Assumption 18 for a discussion of the engine loading.

CAP 061278 identifies minor deficiencies in Emergency DG System Mechanical Calculations based on the initial CR Project review and is consolidated into PassPort AR 00052983.

OE1112771, "OE25315 Fermi 2 – Assessment Identifies Non-Conservatism in EDG Fuel Oil Tank Calculations" identifies industry experience with similar fuel oil tank calculations.

Assumptions:

Validated Assumptions

1. It is assumed that the T-031A/B fuel suction pipes are cut at a 45 degree bevel.
   Basis: This is acceptable because, although the drawing 8410900 (Ref. 18) is not explicit, it implies that the fuel suction pipes have been cut at an angle, and the angle appears to be 45 degrees. This results in the top of the opening (the point at which the fuel siphon would be broken) that is one pipe diameter above the bottom of the pipe.

2. It is assumed that the diesel manufacturer has correctly designed the G-01 and G-02 fuel oil system such that fuel oil pumps P-240A, P-240B, P-241A, and P-241B that feed the G-01/G-02 fuel headers maintain adequate NPSH and do not create an air core vortex throughout the useable volume of the G-01/G-02 skid mounted fuel oil tank.
   Basis: This is acceptable because the skid mounted fuel oil tanks switch positions are being maintained by PBNP to the manufacturer's specified positions per TS-81 and TS-82 which ensure the pump suction pipes will remain submerged. The fuel injection pumps (P-240A, P-240B, P-241A, and P-241B) are positive displacement pumps which can almost develop a full vacuum on the suction pipe. Therefore, the fuel oil fill and injection feed system was designed and is being maintained to assure adequate NPSH is always available to the G-01/02 DG fuel injection pumps.

3. It is assumed that the volume of the lower sloped sections of the G-01/G-02 skid mounted fuel oil tank may be calculated using a triangular cross section (i.e. the radius transitions have negligible effect on calculated volume).
   Basis: This is acceptable because the curved portions of the G-01/G-02 skid mounted fuel oil tank (2" radii) are dimensionally small relative to other cross sectional dimensions (~10% of the overall height, and ~3% of the overall width), and therefore closely approximate an angular transition (see Attachment 4). This assumption serves to address issues noted in OE1112771 regarding tank dimensions.

4. It is assumed that the cross sections of the beam structure forming the top of the G-01/G-02 skid mounted fuel oil tank displace negligible volume.
   Basis: This is acceptable because by inspection of the drawings included in Attachment 4, the structural steel beams occupy ~1% of the total volume, and displace fuel only at the very high end of the tank volume. Therefore, the area of critical interest (i.e. the range of normal fuel pump cycling) is not affected at all. At the high end of the tank volume curve it is the level setting of the high alarm switch that is important, not the corresponding volume.

5. It is assumed that the G-01/G-02 skid mounted fuel oil tank fuel suction tubes are cut at a 45 degree bevel.
Basis: This is acceptable because, although the drawings included in Attachment 4 are not explicit, they imply that the fuel pickup tubes have been cut at an angle, and the angle appears to be 45 degrees. This results in the top of the opening (the point at which the fuel siphon would be broken) is one tube diameter above the bottom of the tube.

6. It is assumed that the bottom end of the G-01/G-02 skid mounted fuel oil tank fuel suction tubes are 1 tube diameter above the lowest point in the skid tanks (i.e. centerline).
Basis: This is a conservative assumption intended to bound the possible tube-end to tank bottom clearance, and to account for any local fuel surface depression (draw-down) while the lines are actively drawing fuel.

7. It is assumed that the G-01/G-02 skid mounted fuel oil tank fuel suction tubes inside the tank are the same diameter as tubing outside of the tank.
Basis: This is acceptable because the tubing appears to pass through a bulkhead fitting at the top of the tank (Attachment 3). This fitting may actually be a union or flange. In any case, it is reasonable to assume that the diameter of the tubing does not change simply due to passing through the tank top.

8. It is assumed that the G-01/G-02 skid mounted fuel oil tank ends are fabricated from ¼" steel plate.
Basis: This is acceptable because the drawings included in Attachment 4 only depict the thickness of the tank sides. It is reasonable to assume that the ends are made of similar thickness material. This dimension is needed since only the overall (outside) length of the tank is depicted.

9. It is assumed that the G-01/G-02 skid mounted fuel oil tank is mounted level.
Basis: This is acceptable because the tank is an integral part of the EDG skid structure. The EDGs must be installed reasonably plumb and level to avoid excessive vibration. This assumption serves to address issues noted in OE1112771 regarding tank dimensions.

10. It is assumed that T-031A/B is well vented and that the pressure in the tank is equal to atmospheric pressure.
Basis: This is acceptable because T-031A/B have a 2" vent pipe per Reference 18 with flame arrestors per drawing M-219-1 (Reference 17) (the flame arrestors do not have Equipment I.D. numbers). At the fuel oil transfer pump flow rate 41 gpm [Input 5] in each of the two fuel oil supply lines, the required air flow rate in the vent pipe would be just above 5 cfm. From Reference 44, the pressure loss in a 2" pipe at 5 cfm is small.

11. It is assumed that T-176A/B is well vented and that the pressure in the tank is equal to atmospheric pressure.
Basis: This is acceptable because T-176A/B have a 4" vent pipe (Reference 2). At the fuel oil transfer pump flow rate 41 gpm [Input 5] in each of the two fuel oil supply lines and taking no credit for fuel oil return line, the required air flow rate in the vent pipe would be just above 5 cfm. From Reference 44, the pressure loss in a 4" pipe at 5 cfm is small.

12. It is assumed that the top of the T-175A/B nozzles are installed level.
Basis: Tank T-175A/B was fabricated with a 6" slope between the working points per Reference 6. Based on a review of the working point elevations [Inputs 21 through 24] the installed slope ranges from 6 7/32" to 6 7/16". A slope of 6 7/16"over the 58'-3" distance [Input 25] between the working points is less than 0.53° which is negligible. This assumption serves to address issues noted in OE1112771 regarding tank dimensions.

13. It is assumed that a 1.2% reduction in the High Heating Value (HHV) is used for Ultra Low Sulfur Diesel (ULSD) fuel. [IMPOSED CONDITION]
Basis: The U.S. Environmental Protection Agency (EPA) finalized new standards for diesel engines and fuels. Sulfur content for land-based non-road diesel fuel are limited to 500 ppm (low sulfur diesel, or LSD) starting in June 2007 and 15 ppm (ULSD) starting in June 2010. The processing required to reduce sulfur to 15 ppm also reduces the aromatics content and density of diesel fuel, resulting in a reduction in volumetric energy content (BTU/gallon). The expected reduction in energy content is 1.2% or more per NRC Information Notice 2006-22 (Reference 74). The reduced energy capacity of the ULSD may result in increased fuel consumption.

To account for this 1.2% reduction the range specific gravity values in the Tech Spec Bases 3.8.3 (Ref. 71) is used. Per Reference 54 the HHV corresponding to the Tech Spec maximum specific gravity of 0.89 is 19,330 Btu/lb. Reducing this HHV by 1.2% gives 19,098 Btu/lb. Per Reference 54 the HHV corresponding to the Tech Spec minimum specific gravity of 0.83 is 19,715 Btu/lb. Reducing this HHV by 1.2% gives 19,478 Btu/lb.

14. It is assumed that the Gas Turbine (G-05) operates with a load less than or equal to 3 MW (the load used to determine the G-05 fuel consumption in Attachment 10).
Basis: See Attachment 11 for justification of this assumption.

15. It is assumed that the two Heating Boilers (Z-032A and Z-032B) cease operation on a loss of offsite power.
Basis: With a loss of offsite power, only emergency power is available. Per Reference 78 busses that power the Heating Boilers (B22 and 2B-31) are not in service on loss of offsite power.

16. It is assumed that expansion joint and flexible hose pressure loss is approximately three (3) times that of steel pipe.
Basis: The manufacturer of the expansion joints in the FO system are unknown and therefore all dimensional parameters are also unknown. It is known that the expansion joints are small in size (1" to 2") per References 20 and 24 therefore they are assumed to be a flex type hose or braided hose. Per OmegaFlex (Reference 75), a Manufacturer of Flexible Metal Hose and Braid Products, the amount of pressure loss is approximately three (3) times that of steel pipe. Thus, for the calculation of head loss, the expansion joint and hose length is multiplied by three (3) and added to the length of straight pipe.

17. It is assumed that the fuel consumption rate (expressed in gal/kw-hr) of G-03/G-04 at the 195 hr rating (2951 kw) is equal to that at the 2000 hr rating (2848 kw).
Basis: Fuel oil consumption data for G-03 and G-04 is provided in References 3 and 49 up to 2860 kw [Input 11]. For G-03, the consumption rate data shows a consistent downward trend as the generator output increases. For G-04, the fuel consumption rate decreases up to 2600 kw and remains essentially the same at 2860 kw. For G-01 (the only EDG to be tested above the 195 hr rating), the fuel consumption rate was lower than that near its 2000 hr

rating.

18. It is assumed that for the purposes of determining fuel oil consumption for the first 48 hour period of EDG operation, the 2000 hr engine rating for G-01 and G-02 and the 195 hr engine rating for G-03 and G-04 represents average loading for the operating scenarios and that for the purposes of determining fuel oil consumption for the seven day operation of EDG, the 2000 hr engine rating for G-01 and G-02 and the 2000 hr engine rating for G-03 and G-04 represents average loading for the operating scenarios.
Basis: See Attachment 20 for a justification of this assumption.

19. It is assumed that for the purposes of determining fuel oil consumption, the average temperature of the fuel oil is nominally at 60°F.
Basis: Fuel oil is stored in small day tanks near the EDGs and in large capacity buried storage tanks. Fuel in the day tanks is at the normal ambient temperature of the storage tank rooms prior to the start of the engines. These rooms will heat up as the engine operates. The buried storage tanks are normally at the soil temperature at their average depth. The volume of fuel below ground is significantly larger than that in the day tanks. Based on the fuel consumption rates and the day tank size, fuel pumped from the below ground storage tanks will not significantly heatup as the engine operates when used to support the 48 hr and seven day fuel consumption calculations (which are based on engine operating at rated capacity).

20. It is assumed that for the purposes of determining fuel oil consumption, the BHP for rebuilt SW pumps at the predicted minimum operating flow will be less than that predicted in Calculation 99-0052.
Basis: PBNP is in the process of rebuilding the SW pumps and is selecting a rebuild design to reduce the pump shutoff head and the BHP requirements at low flow. With a given resistance curve as defined in Calculation 99-0052, lower head at low flows would mean that the flow per pump would decrease. Even at the lower flow, the BHP on the rebuild design will be below that on the curves used in Calculation 99-0052. This assumption creates an IMPOSED condition on the SW pump rebuild design.

Unvalidated Assumptions

None

Acceptance Criteria:

There are no numerical acceptance criteria for the portion of this calculation that documents the basis for the level switch settings on the Fuel Oil Storage Tanks (T-175A and T-175B), the EDG Day Tanks (T-031A, T-031B, T-176A, and T-176B) and the G-01/G-02 Skid Mounted Fuel Oil Tank.

For the process limit for the minimum indicated level for the Fuel Oil Storage Tanks (T-175A and T-175B), 11,000 gallons of fuel shall be maintained by each train to satisfy Tech Spec 3.8.3 and its associated bases Tech Spec Bases B 3.8.3 (Reference 71).

For the Inservice Testing Criteria acceptance criteria for the Fuel Oil Transfer Pumps (P-206A, P-206B, P-207A, and P-207B), the pumps shall provide more fuel oil to the day tanks (T-031A, T-031B, T-176A, and T-176B) than is being consumed by the EDG's.

There are no numerical acceptance criteria for the portion of this calculation that generates the curve showing the indicated level by sight glass versus the gallons of usable fuel in the G-02 EDG Skid Mounted Fuel Oil Tank.

There are no numerical acceptance criteria for the portion of this calculation that generates the curve showing the % indicated level versus total tank volume in the Fuel Oil Storage Tanks (T-175A/B).

The portion of the calculation that validates the Technical Specification fuel oil consumption for the 48 hour run of one EDG at rated load, shall show that the consumption is less than 11,000 gallons (Tech Spec 3.8.3 and associated bases Tech Spec Bases B 3.8.3, Reference 71).

For the portion of the calculation that validates that the seven day operation of one EDG at required loads with tanks T-175A/B cross tied shall demonstrate that sufficient fuel oil is maintained between the combined volume of T-175A and T-175B to allow operation of one diesel continuously at the required load for seven days (Tech Spec Bases B 3.8.3, Reference 71).

For the portion of the calculation that validates that the two hour operation of one EDG at required loads can be met by the EDG Day Tanks shall demonstrate sufficient fuel oil is maintained in the EDG fuel oil day tanks (T-031A/B plus G-01/G-02 Skid Mounted Tanks for G-01/G-02 and T-176A/B for G-03/G-04) to allow operation of one EDG for two (2) hours at rated load (Reference 72).

For Appendix R Compliance, adequate fuel oil storage must be available to support operation of Two EDGs or the Gas Turbine for the 72 hour duration of the Appendix R event (Reference 61). For Appendix R Compliance, adequate fuel oil supply must be available to support operation of the diesel driven fire pump for an 8 hour period (Reference 59, pg. 2-3).

Fuel Oil Transfer Pump Testing Acceptance Criteria:

Fuel oil transfer pumps P-206A, P-206B, P-207A, and P-207B are positive displacement pumps that transfer fuel from storage tanks T-175A&B to day tanks T-031A, T-031B, T-176A, and T-176B. Pressure control valves at the pump discharges (FO-03982A, FO-03982B, FO-03983A, and FO-03983B) are designed to bypass flow from the fuel oil transfer pumps to limit pressure at the pump discharge to their setpoint of 26 psig. Empirical data in References 66, 67, and 68 demonstrate that these valves do not have sufficient capacity to limit system pressure to their setpoint. This data indicates that the valve results in normal system pressures of approximately 50 psig with flows to T-176A and T-176B of 28 to 30 gpm. The operational impact of the actual system pressures and flows has been evaluated and documented in Reference 69.

Per Section 10 of Reference 12, the fuel oil transfer pumps should have the capability of supplying fuel oil to the day tanks at a rate six times the engine fuel oil consumption rate. Thus, the capacity of P-206A and P-207A ($q_{P-206A/P-207A}$) must be:

$$q_{P-206A/P-207A} = 6 \cdot q_{G-01/G-02} \qquad \text{Eqn. 18A}$$

and, the capacity of P-206B and P-207B ($q_{P-206B/P-207B}$) must be:

$$q_{P-206B/P-207B} = 6 \cdot q_{G-03/G-04} \qquad \text{Eqn. 18B}$$

Where:

$q_{G-01/G-02}$ = Fuel oil consumption rate for G-01/G-02
$q_{G-03/G-04}$= Fuel oil consumption rate for G-03/G-04

The factor of six used to establish the pump capacity requirements provides margin for changes in fuel properties due to temperature variations and to minimize cycling of the pumps during diesel operation.

Process Limits for Fuel Oil Storage Tank and Fuel Oil Day Tank Level Switch Settings:

Fuel Oil Day Tanks T-031A/B:

Settings of LS-03930B/LS-03931B and LS-03930A/LS-03931A turn pumps P-206A and P-207A On and Off to control the supply of fuel to day tanks T-031A/B. There are no prescribed requirements for the stored volume of fuel in tanks T-031A and T-031B. Reference 45 provides guidance on the selection of tank level alarm setpoints ("one or more day or integral tanks whose capacity is sufficient to maintain at least 60 minutes of operation after reaching the low level alarm setpoint. The integral and day tanks may be combined in establishing the available capacity," and "fuel consumption with the diesel running at 100 percent continuous rated load plus a minimum additional margin of 10 percent based on the minimum quality fuel oil that is acceptable and the most adverse operating conditions"). Additionally, Reference 45 provides guidance that automatic transfer of fuel should be initiated before actuation of the low alarm and that the day tank capacity should be sufficient to preclude excessive cycling of the transfer pump.

Based on a review of the physical dimensions for the G-01/G0-02 skid mounted tanks and T-031A/B, it is clear that a significant quantity of fuel is available in these tanks. As such, a quantitative assessment of the setpoints is not performed herein.

Fuel Oil Day Tanks T-176A/B:

Settings of LS-03991A/B turn pumps P-206B and P-207B On and Off to control the supply of fuel to day tanks T-176A/B. Revision 2 of this calculation used the following criteria for assessing the T-176A/B setpoints:

- The low level (pump on) is set at one hour of fuel remaining. The volume at the low level is determined by summing the fuel oil consumption for one hour with the unusable volume.
- The high level (pump off) is set to provide enough fuel for two hours of continuous operation at 100% rated load. The volume at the high level is determined by summing the fuel oil consumption for two hours and the unusable volume.

- Settings of LS-03935A/B are chosen to provide High and Low Level alarms for Day Tank T-176A/B if LS-03991A/B fails and is not maintaining or is overfilling Day Tank T-176A/B.

The levels switches used for T-176A/B have fixed actuation positions. As such, the actual setpoints, as defined in Input 71, are assessed versus this criteria based on fuel consumption rates for the minimum quality fuel oil that is acceptable and the most adverse operating conditions. Equation 8A is used to determine the volumes based on actual setpoints and these are compared with the volumes calculated using the above criteria.

The level with respect to the top of the level switch flange is determined by subtracting the calculated level from the distance from the top of the mounting flange to the inside bottom of the tank (64.5" [Input 67]).

G-01/G-02 Skid Mounted Fuel Oil Tanks:

See the discussion on the setpoints for tanks T-031A and T-031B.

Fuel Oil Storage Tanks T-175A/B:

PBNP Technical Specification 3.8.3 requires maintaining at least 11,000 gallons in each fuel oil storage tank. This level is monitored via a level transmitter on the tank and a level indicator.

As discussed on Page 34, Tanks T-175A and T-175B are installed with a 0.53° slope with a vertical distance between the working points of 6 7/16". The horizontal distance from the centerline of the instrument mounting flange to the closest working point is 12'-1 ½" [Input 72]. Thus, the tank is 1.35" [=(sin 0.53°)·(12'-1 ½")·(12·in/ft)] lower at the level switch than at the nearest working point and 5.09" [=6 7/16" - (sin 0.53°)·(12'-1 ½")·(12 in/ft)] higher than the furthest working point.

The level in the dished head nearest the level switch is equal to the level gauge reading minus 1.35" and the level in the dished head furthest from the level switch is equal to level reading plus 5.09". Equation 5A is used to determine the volume in each dished head based on these levels. The level in the cylindrical portion of the tank is determined based on the average of the levels at the two ends using Equations 6A and 6B. The required height in the tank is solved iteratively to achieve the desired volume. The results are expressed in terms of height from the inside bottom the tank. The small slope of the tank has a negligible impact on the vertical distance {i.e., 10'-0" ≈ [10'-0"/(cos 0.53°)}.

The LS-03933A/B low level setpoint is used for a local alarm to alert the operator that action should be taken to replenish the tank to avoid encroaching on the Technical Specification minimum volume. This setpoint should be set above the minimum level required level to meet the Technical Specification requirement. The tank volume at a range of levels is solved and the setpoint is then computed. The level setpoint is expressed in terms of the distance from the face of the mounting flange. The mounting flange on T-175A is located at EL 28'-3 1/8" [Input 27] and on T-175B is located at EL 28'-3 1/4" [Input 28]. The higher elevation on T-175B is conservatively used herein. The working point elevation nearest the level switch is EL 19'-8 3/8" [Input 23], the difference in level between the working point and the level switch is 1.35" and the diameter of the tank is 10'-0" [Input 20]. Thus the elevation of the inside bottom of that tank at the level switch is:

$$EL_{LS-03933A/B\ Bottom} = (19'\text{-}8\ 3/8") - 1.35" - \left(\frac{10'\text{-}0"}{2}\right) = 13.348\ \text{ft}$$

The distance from the tank bottom to the face of the level switch mounting flange is then:

$$l_{LS-03933A/B} = (28'\text{-}3\ 1/4") - (13.348\ \text{ft}) = 14.923\ \text{ft} = 179\ \text{inches}$$

The high level alarm is a local alarm that has no safety function and therefore is not determined in this calculation.

Fuel Oil Storage Capacity to Support EDG Run Times:

The Fuel Oil Storage Tanks T-175A/B and the EDG Day Tanks T-031A/B and T-176A/B must contain sufficient Fuel Oil to allow one EDG to operate for 48 hours at rated load, to allow one EDG to operate continuously at the required load for 7 days, and to allow one EDG to operate for 2 hours at rated load.

EDG Run Time of 48 Hours at Rated Load

The volume of fuel oil that would be consumed by a 48 hour run of one EDG at rated load is calculated by multiplying the G-01/G-02 fuel oil consumption rate determined in the methodology above and the G-03/G-04 fuel oil consumption rate determined in the methodology above by the time of operation and the load at the 2000 hr rating of the EDG [Input 6 and 7].

The larger of the two consumed volumes must be less than 11,000 gallons (Tech Spec Bases B3.8.3 Reference 71).

EDG Run Time of 7 Days at Rated Load

The volume of fuel oil that would be consumed by a 7 day run of one EDG at rated load is calculated by multiplying the G-01/G-02 fuel oil consumption rate determined in the methodology above and the G-03/G-04 fuel oil consumption rate determined in the methodology above by the time of operation and the load at the 2000 hr rating of the EDG [Input 6 and 7].

The larger of the two volumes must be less than the usable volume of the combined storage of the tanks (T-175A and T-175B).

EDG Run Time of 2 Hours at Rated/Short Term Accident Load

The volume of fuel oil that would be consumed in 2 hours of one EDG operation is calculated by multiplying the G-01/G-02 fuel oil consumption rate determined in the methodology above by the time of operation and the load at the 2000 hr rating of the G-01/G-02 EDG [Input 6].

Per Reference 84 the G-03/G-04 engine load may be 2951 KW for the first 1 to 4 hours therefore the consumed volume in 2 hours of operation is based on the 195 hr load rating. The volume of fuel oil that would be consumed in 2 hours of one EDG operation is calculated by multiplying the G-03/G-04 fuel oil consumption rate determined in the methodology above by the time of operation and the short term accident load [Input 8].

The resulting consumed volume of G-03/G-04 must be less than the usable volume in each day tank (T-176A and T-176B) and the resulting consumed volume of G-01/G-02 must be less than the usable volume in each G-01/G-02 skid mounted fuel oil tank.

Tank Usable Volume:

Fuel Oil Day Tanks T-031A/B:

The usable volume within a tank is determined by subtracting the unusable volume from the volume corresponding to the Transfer Pump OFF setpoint. Equation 7A is used to determine the volume based actual setpoint [Input 70]. Since the setpoint is expressed in terms of the level span, dimensions for the span between the level taps and the distance from the centerline of the lower tap to the inside bottom of the tank are used to determine the height above the bottom of the tank for use in Equation 7A.

Fuel Oil Day Tanks T-176A/B:

The usable volume within tanks T-176A/B is determined by subtracting the unusable volume from the volume corresponding to the Transfer Pump OFF setpoint. This volume is calculated as part of the assessment of the T-176A/B setpoints.

G-02 Skid Mounted Fuel Oil Tank Level:

From inspection of the drawings provided by the EDG manufacturer (Attachment 4), it is apparent that the usable volume of the tank is entirely contained in the portion with vertical sides forming a right parallelepiped. This indicates a straight linear relationship between indicated level in the sight glass and gallons of usable capacity.

The first step is to establish the minimum level of oil in the tank that will still cover the open lower ends of the suction tubes. Correlating this to the sight glass indication using the calibration data for the glass will provide the coordinates for the left most point on the curve. Since the unusable volume is both non-linear with respect to level glass indication, and irrelevant for operating the EDG, this figure will simply be noted with the TLB graph for use in estimating the volume to be drained during maintenance.

The second step is to determine the slope of the fuel curve. This is a simple matter of determining the incremental volume in gallons for each inch of indicated level. With these two steps completed, the level vs. volume curve can be plotted.

The final step is to indicate the manufacturer's recommended level switch settings on the graph. By inspection it is apparent that the manufacturer's settings are based on total tank volume and not usable volume.

Fuel Oil Storage Tanks T-175A/B:

Technical Specification Bases TS B3.8.3 requires that 11,000 gallons of useable volume must be available in both T-175A and T-175B. This volume is ensured by maintaining a specific tank level as read on a level indicator. Therefore, the unusable volume must be added to 11,000 gallons to determine the process volume.

The level indication for each tank is scaled 0'-6" to 10'-0" equal to 0% to 100% [Inputs 29 and 30]. Per References 6 and 24, the level transmitters and switches are located the same distance from the working points of the tank. Thus, the approach outlined on Page 37 for determining the volume at the level switch is applicable to that at the level indicator. The tank volume at a range of levels is solved and the tank volume versus indicated level (in %) is plotted. The process level associated with the process volume is then computed.

Technical Specification Bases TS B 3.8.3 also states that sufficient fuel is normally maintained to allow one diesel to operate continuously at the required load for 7 days. The bounding fuel consumption rate is used to determine the quantity of usable fuel required to meet this normal supply. As noted in Technical Specification Bases TS B 3.8.3, Tank T-175A and T-175B can be cross-tied so this volume could be shared between the two tanks.

Level Switch Uncertainty

The level switches used for alarms, 'Pump On' and 'Pump Off' conditions on T-176A/B (LS-03991A/B) and T-031A/B (LS-03930A/B and LS-03931A/B), high and low alarms for T-176A/B (LS-03935A/B) and low alarms on T-175A/B (LS-03933A/B) are GEMS (IMO) model LS-800 non-adjustable float switches (Passport and Reference 10). From the vendor correspondence (Reference 10), the repeatability uncertainty of the level switches is about 0.031 (1/32) inches and the switches were factory set using water (SG = 1.0). The acceptable range for specific gravity of the diesel fuel oil is 0.89 to 0.83 (Average = 0.86) [Input 14]. From the vendor correspondence, this represents an uncertainty of only 0.12 inches (1.31 inches (SG @ 0.85) – 1.19 inches (SG @ 1.0)). Therefore, the uncertainty associated with the level switches LS-03991A/B, LS-03930A/B, LS-03931A/B, LS-03935A/B and LS-03933A/B is considered to be negligible.

Appendix R Compliance:

EDG Fuel Oil Storage

The fuel consumption rate for G-01/G-02 exceeds that for G-03/G-04 and will be used for the Appendix R compliance evaluation.

The volume of fuel oil that would be consumed by a 72 hour run of two EDG's at rated load is calculated by multiplying the G-01 and G-02 fuel oil consumption rate determined in the methodology (Page 21) by the time of operation and the load at the 2000 hr rating of the EDG's [Input 6].

The required volume calculated based on EDG fuel consumption rates must be less than the usable volume in the storage tanks (T-175A plus T-175B).

Gas Turbine Fuel Oil Storage

The Fuel Oil Storage Tanks T-032A and T-032B must contain sufficient fuel oil to allow the Gas Turbine to operate for 72 hours at a 3 MW load.

The volume of fuel oil that would be consumed by a 72 hour run of the Gas Turbine (G-05) is calculated by multiplying the G-05 fuel oil consumption rate at 3 MW load [Input 63] by the time of operation.

The results of the fuel consumption calculation will be used as input to a calculation that determines the minimum level of fuel oil needed in the fuel oil storage tanks (T-032Aand T-032B) for Appendix R requirements.

Fire Pump Diesel Engine Fuel Oil Storage

The Fuel Oil Storage Tank T-030 must contain sufficient fuel oil to allow the fire pump to operate for 8 hours at maximum load. Per Reference 57, the tank capacity is reduced by 5% for the volume of the sump and by 5% for expansion.

Results and Conclusions:

This basis for the EDG fuel oil tank level switch settings are as follows:

EDG Day Tanks (T-031A, T-031B, T-176A and T-176B)

- There are no prescribed requirements for the combined stored volume of fuel in tank T-031A/B and its associated skid mounted fuel oil tank. Based on a review of the physical dimensions for the G-01/G0-02 skid mounted tanks and T-031A/B, it is clear that a significant quantity of fuel is available in these tanks (see discussion on Page 57). As such, a quantitative assessment of the setpoints is not performed herein.
- The 'Pump On' setpoint for T-176A/B at 27" above the inside bottom of the tank ensures that at least 1 hour of fuel remains below the pump on setpoint.
- The 'Pump Off' sepoint for T-176A/B at 48" above the inside bottom of the tank. The usable volume in T-176A/B is slightly less (1.4 gallon=443.6–445.0) than the quantity to ensure 2 hours of fuel oil are available in the tank. The 2 hour duration was a sizing criteria for the tank and was originally based on a consumption rate for operation of an EDG at 100% of the 2000 hour load rating of 2848 kW. The difference in storage volume is roughly 20 seconds of fuel oil consumption. This volume is considered to be acceptable to meet the guidance of Reference 45 to preclude excessive cycling of the transfer pump.

Fuel Oil Storage Tanks (T-175A and T-175B)

- The T-175A/T-175B low level alarm setpoint must be at least 43.53" above the bottom of the tank (or less than 135.47 inches below the face of the mounting flange) to alert the operator that the level is falling below the Technical Specification minimum usable volume of 11,000 gallons.
- The T-175A/T-175B high level alarm is a local alarm with no safety function and as such a process limit is not determined herein.

The process limit for the minimum indicated level for the Fuel Oil Storage Tanks (T-175A and T-175B) is 43.53" above the bottom of the tank (or 32.92% indicated level) to ensure that the usable volume of fuel in the tank exceeds 11,000 gallons.

The IST acceptance criteria for the Fuel Oil Transfer Pumps (P-206A, P-206B, P-207A, and P-207B) flow capability to their associated day tanks (T-031A, T-031B, T-176A, and T-176B) are:

- Pumps P-206A or P-207A flow capability to their associated day tanks (T-031A or T-031B) is 21.8 gpm.

- Pumps P-206B or P-207B flow capability to their associated day tanks (T-76A or T-176B) is 22.3 gpm.

A curve showing the indicated level by sight glass versus the gallons of usable fuel in the G-01/G-02 EDG Skid Mounted Fuel Oil Tank is provided in Figure 4 on Page 54. This curve also depicts the fuel oil transfer level switch set points.

A curve showing the % indicated level versus the total T-175A/B Fuel Oil Storage Tank volume (in gallons) is provided in Attachment 19.

This calculation determined that the volume of fuel required for a 48 hour run is 10,479 gallons for G-01/G-02 and 10,680 gallons for G-03/G-04. This validates the Technical Specification required volume of 11,000 gallons.

This calculation determined that the volume of fuel required for seven day operation of one EDG at required load is 36,676 gallons for G-01/G-02 and 36,076 gallons for G-03/G-04. Figure 3 on Page 53 provides a chart of the acceptable level combinations to meet this storage requirement. The capacity of each tank is 35,000 gallons (per Attachment 19) with a maximum usable volume in each tank of approximately 34,360 gallons (per Attachment 19).

This calculation determined that the volume of fuel required for two hour operation is 436.6 gallons for G-01/G-02. The combined usable volume in T-031A/B (424.9 gallons) and the G-01/G-02 Skid Mounted Tanks (426.4 gallons) exceeds the G-01/G-02 two-hour operation fuel oil consumption (436.6 gallons) by 414.7 gallons (=424.9+426.4–436.6).

This calculation determined that the volume of fuel required for two hour operation is 445.0 gallons for G-03/G-04. The usable volume in T-176A/B is slightly less (1.4 gallon=443.6–445.0) than the quantity to ensure 2 hours of fuel oil are available in the tank. The 2 hour duration was a sizing criteria for the tank and was originally based on a consumption rate for operation of an EDG at 100% of the 2000 hour load rating of 2848 kW. The difference in storage volume is roughly 20 seconds of fuel oil consumption. This volume is considered to be acceptable to meet the guidance of Reference 45 to preclude excessive cycling of the transfer pump.

This calculation validated that the fuel oil storage in Tanks T-175A, T-175B, T-031A, T-032B and T-030 support the Appendix R operation as follows:

Two EDGs (G-01, G-02, G-03 or G-04) or the Gas Turbine (G-05) for the 72 hr duration of the Appendix R Event

- G-01 and G-02 consume 31,450 gallons in the 72 hour Appendix R event duration. This is less than the normally maintained usable volume of the T-175A/B Fuel Oil Storage Tanks (approximately 34,360 gallons per Attachment 19) and thus meets the acceptance criteria.
- Gas Turbine (G-05) consumes 75,774 gallons of fuel oil in the 72 hour Appendix R event duration. This value provides input to a calculation that determines the minimum level of fuel oil needed in the fuel oil storage tanks (T-032Aand T-032B) for Appendix R requirements.

Diesel Engine for Fire Pump P-035B (P-035B-E) Operation for 8 Hours

- The fire pump diesel engine consumes 136 gallons in the 8 hour required operating period for Appendix R compliance. This is less than the available volume of 180 gallons in storage tank T-030.

This calculation creates an imposed condition for the Fuel Oil receipt inspection to ensure that the Higher Heating Value of fuel oil transferred to T-175A/B is at least 19,098 Btu/lb at the Tech Spec maximum specific gravity of 0.89 and at least 19,478 Btu/lb at the Tech Spec minimum specific gravity of 0.83.

This calculation creates an imposed condition for the Pump ON and Pump OFF setpoints for tank T-031A/B (LS-03930A, LS-03930B, LS-03931A and LS-3931B).

This calculation creates an imposed condition for the Pump ON and Pump OFF setpoints for tank T-176A/B (LS-03991A/B).

This calculation creates an imposed condition for the SW pump rebuild design. This imposed condition is tracked via GAR 01150878.

ENCLOSURE 9

NEXTERA ENERGY POINT BEACH, LLC
POINT BEACH NUCLEAR PLANT, UNITS 1 AND 2

LICENSE AMENDMENT REQUEST 261
EXTENDED POWER UPRATE
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION

ADDITIONAL INFORMATION - QUESTION 6 RESPONSE
ETAP AC SYSTEM ANALYSIS FOR EPU

134 pages follow

ETAP ANALYSES OF AC SYSTEM FOR EPU

The overall purpose of this calculation was to perform the AC electrical system calculations that support the design and licensing basis of Point Beach Nuclear Plant following installation of the Alternate Source Term (AST) and Extended Power Uprate (EPU) modifications. This calculation utilized ETAP to perform the analysis.

The following analyses are included in this calculation:

II. Short Circuit Analysis - The short circuit analysis includes the evaluation of the individual breakers and electrical bus work from the 13.8 kV system through the 480V system.

III. Degraded Voltage Analysis - The degraded voltage analysis includes determining the minimum 4.16 kV system voltage, minimum 345 kV system voltage, motor starting analysis and the setpoint calculation for the degraded voltage relays.

IV. Emergency Diesel Generator (EDG) Steady State Loading Analysis - The Emergency Diesel Generator Steady State Loading Analysis includes evaluation of loading for Diesel Generators G-01, G-02, G-03, and G-04. The results of the calculation will include loading values that will provide the basis for FSAR Section 8.8, as well as Unit 1 and Unit 2 AOP-22 "EDG Load Management" tables for KW values listed in the tables.

V. Maximum Voltage Analysis - The Maximum Voltage analysis includes an evaluation of maximum voltage for all equipment on the 13.8kV system through the 480V system to ensure all equipment is within its maximum voltage rating (including protective devices, motors, cables, static loads and fuses).

Each is described further below.

II. SHORT CIRCUIT ANALYSIS

The purpose of the short circuit analysis is to determine the three phase short circuit currents at plant equipment contained in the AC Electrical Distribution System to assure the equipment is capable of withstanding and interrupting the maximum possible fault current in the system. The electrical system plant alignments are used to ensure the maximum possible fault current for each plant equipment is determined.

The scope of the short circuit analysis is limited to the bounding electrical system plant alignments to determine the maximum fault current for the following 13.8 kV, 4.16 kV and 480 V buses including their associated breakers.

METHODOLOGY

The following steps develop the maximum three phase short circuit currents at plant equipment within the AC Electrical Distribution System. The plant equipment evaluated are Switchgear, Motor Control Centers, Power Panels, Circuit Breakers, and Fuses.

Step 1 - Establish AC Electrical Distribution System Model

The AC electrical distribution system model is developed and contains the technical data, equipment demand factors, and operating (e.g. ON/OFF, brake horsepower, etc.) status for plant equipment from the 345 kV system through the 480 V system in ETAP. The model in ETAP will be utilized to determine the maximum three phase short circuit current at various plant equipment.

Step 2 - Establish Plant Operating Conditions (Scenarios/Cases)

The plant operating conditions were developed and then the worst-case condition for the unit being evaluated was determined. The plant operating conditions evaluated were consistent with plant operation, plant operating procedures, design basis events and licensing commitments to ensure the worst case three phase short circuit currents are established.

Step 3 - Establish Sources Maximum System Pre-Fault Voltages

The maximum pre-fault voltages for 345 kV system, the main unit generators, the gas turbine and the EDGs (G-01, G-02, G-03, and G-04) are developed. (1) The maximum 345 kV system is based on the maximum allowable voltage within the normal range. (2) The maximum pre-fault voltages for the main unit generators and the gas turbine generator are based on the maximum allowable voltage per plant operating procedures. (3) The emergency diesel generators voltages are based on the maximum MVARs allowed during the monthly surveillance per plant operating procedures.

The maximum voltages provide the worst-case system voltages for the 345 kV through the 480 V systems. This will provide the worst-case pre-fault voltage. The three-phase fault current is directly proportional to the pre-fault voltage; therefore this will provide the worst-case fault current for plant equipment. If pre-fault voltages above 504 V are obtained at any 480 V switchgear, MCC, or power panel the 345 kV switchyard voltage will be reduced to ensure that the 480 V interrupting ratings for the circuit breakers can be used. If adjustment is required, this will provide the basis for establishing a new maximum allowable voltage value for the 345 kV switchyard.

Step 4 - Establish Cable Impedance Temperature

The cable temperature at which the cable impedance is calculated for the short circuit analysis is developed. The cable impedance temperature utilized to perform the short circuit analysis is 25 degrees centigrade and provides a conservative temperature to ensure the maximum system short circuit condition. The minimum operating temperature of 25 degrees centigrade accounts for a fault occurring upon energization of the equipment. The 25 degrees centigrade temperature is conservative because a lower cable temperature (when compared to cable design operating temperature of 90 degrees centigrade) will result in lower cable impedances, which will be conservative for calculating fault currents.

Step 5 - Determination of Equipment's Maximum Pre-Fault Voltage

The short circuit current is proportional to the pre-fault voltage calculated at the equipment. The equipment maximum pre-fault voltage is calculated using the ETAP load flow analysis module at each piece of equipment from the 345 kV system down to the 480 V system. The Newton Raphson iterative technique is used to calculate the equipment voltages for each plant operating condition evaluated.

Step 6 - Determination of Short Circuit at Plant Equipment

The short circuit Calculation will use IEEE std. C37.010-1999, IEEE Std. C37.13-1990, IEEE Std. 141-1993 and IEEE Std. 242-2001 to determine the maximum fault current for high, medium and low voltage systems. There are two types of short circuit currents calculated:

1. ½ cycle network (subtransient network)
2. 1.5-4 cycle network (transient network)

The ½ cycle network currents, also called momentary currents, are the currents at ½ cycle after a fault initiation. They relate to the duty to which circuit breakers are subjected when "closing against" or withstanding short circuit currents. These currents are also referred to as "close and latch" currents. Often these currents contain dc offset, and they are calculated on the premise of no ac decrement in the contributing sources, i.e. the machine reactance remains sub-transient. Since low-voltage breakers operate in the first cycle, their interrupting ratings are compared to these currents. The 1.5-4 cycle network currents are the short circuit currents in the time interval from 1.5 to 4 cycles after fault initiation. They relate to the currents flowing through the interrupting equipment when isolating a fault. Hence, they are also referred to as "contact-parting" currents. These currents are asymmetrical, i.e. they contain DC offset, but due consideration is given to ac decrement because of the elapsed time from the fault inception. All contributing sources are taken into account when calculating interrupting currents by virtue of reactances that range from sub-transient to transient. Interrupting currents in the 1.5 to 4 cycles interval are only associated with medium and high-voltage breakers.

The short circuit calculation is developed using a "combination ½ cycle network." This is based on the interpretation of IEEE Std. C37.010-1999 and IEEE Std. C37.13-1990 (References VII.2.01 and VII.2.02) because the initial symmetrical RMS magnitude of the current contributed to a terminal short circuit might be 6 times rated for a typical induction motor. Large low-voltage induction motors (described as *all others, 50 hp and above*) use a *4.8 times rated current ½* cycle estimate, which is effectively the same as multiplying the sub-transient impedance by approximately 1.2. For this motor group, there is reasonable correspondence of low- and high-voltage procedures. Induction motors *smaller than 50 hp* a conservative estimate is *3.6 times rated current* (equivalent of 0.28 per unit impedance) ½ cycle assumption of low-voltage standards. This is effectively the same as multiplying sub-transient impedance by 1.67. The single ombination ½ cycle network adds conservatism to both low- and high-voltage standard calculations. It increases calculated ½ cycle short circuit currents at high voltages by the contributions from small induction motors and at low voltages, when motors are 50 HP or larger, by the increased contributions of larger low-voltage induction motors. The combined network rotating machine reactance (or impedance) multipliers in IEEE Std. 141-1993 are applied automatically by ETAP when the short circuit analysis is performed.

The total short circuit current calculated in this analysis is the total asymmetrical current. The asymmetrical short circuit current wave is composed of two components. One is the ac symmetrical component (E/Z). The other is a dc component initially of maximum possible magnitude equal to the peak of the initial ac symmetrical component, or, alternatively, of the magnitude corresponding to the highest peak (crest) assuming that the fault occurs at the point on the voltage wave where it creates this condition. At any instant after the fault occurs, the total current is equal to the sum of the ac and dc components.

Since resistance is always present in an actual system, the dc component decays to zero as the stored energy it represents is expended in I^2R loss. The decay is assumed to be an exponential, and its time constant is assumed to be proportional to the ratio of reactance to resistance (*X/R* ratio) of the system from source to fault. As the dc component decays, the current gradually changes from asymmetrical to symmetrical.

Asymmetry is accounted for in simplified calculating procedures by applying multiplying factors to the alternating symmetrical current. A multiplying factor is selected that obtains a resulting estimate of the total (asymmetrical) RMS current or the peak (crest) current, as appropriate for comparison with equipment ratings, capabilities, or performance characteristics that are expressed as total (asymmetrical) RMS currents or peak (crest) currents.

The alternating symmetrical current may also decay with time, as indicated in the discussion of sources of short-circuit current. Changing the impedance representing the machine properly accounts for ac decay of the current to a short circuit at rotating machine terminals. The same impedance changes are assumed to be applicable when representing rotating machines in extensive power systems.

The following are the steps performed to determine the maximum short circuit current for plant equipment:

1. Calculate the maximum pre-fault voltage at plant equipment.

2. Based on the maximum pre-fault voltage, calculate the maximum symmetrical short circuit current at plant equipment using ETAP. ETAP uses the E/Z methodology described in ANSI/IEEE standards using separate reduction of single equivalent R and X networks. The symmetrical RMS current is determined by ETAP for the ½ cycle and 1.5-4 cycle networks. The 1.5-4 cycle network is determined by the contact parting time of the breaker to interrupt the fault. An X/R ratio is obtained for each individual faulted bus and short circuit current, which is used to determine the multiplying factors to obtain the asymmetrical value of the momentary and interrupting short circuit currents. A short circuit study case and its associated options were developed for each plant operating condition.
3. The evaluation of the 480V switchgear and MCCs is based on the ANSI/IEEE standards for symmetrical and asymmetrical current (Reference VII.3.01). ETAP applies the ANSI multiplying factor to the symmetrical RMS current and compares it to the equipment rating.
4. The evaluation of the momentary and interrupting rating of the 13.8 kV and 4.16 kV switchgear power circuit breakers is based on ANSI/IEEE standards and determined using ETAP.
5. The evaluation of the interrupting rating of the 480 V Switchgear power circuit breakers is based on the ANSI/IEEE standards and determined using ETAP. ETAP compares the calculated short-circuit current to the rating for the power circuit breakers. However, ETAP is unable to evaluate if the pre-fault voltage is greater than rating of the power circuit breaker inputted for the circuit. Therefore, a circuit may fail because the pre-fault voltage exceeds the rating of the equipment. The following is performed to evaluate the power circuit breakers: a review of the pre-fault voltage will be performed and the calculated fault current by ETAP will be compared against the appropriate rating if greater than the maximum voltage rating of the breaker. If the pre-fault voltage is greater than the maximum voltage rating, then the breaker will be considered to have failed.
6. The evaluation of the interrupting rating of the 480V MCC and 480V power panel molded case circuit breakers and fuses is performed manually based on the ANSI/IEEE standards. The molded case circuit breakers are manually evaluated because ETAP does not evaluate OFF circuits and breakers contained with schedules (e.g. power panels). Additionally, as with 480 V switchgear breakers, ETAP is unable to evaluate whether the prefault voltage is greater than the nominal 480V short circuit rating for each breaker. Therefore, the molded case circuit breakers for both MCCs and power panels are evaluated as follows:

   The interrupting symmetrical short circuit current for low voltage circuit breakers is determined using the ½ cycle network because the circuit breakers are rated based on the maximum symmetrical current at an instant ½ cycle after the fault. The low voltage circuit breakers are rated based on the maximum short circuit current (symmetrical current) on the source side of the breaker based on a test power factor (or X/R ratio). A multiplying factor is required to be calculated if the calculated system X/R ratio is greater than the test X/R ratio. The symmetrical current is then corrected prior to comparison to the breaker interrupting rating. Therefore, the following equation is used to determine the multiplying factor of the calculated symmetrical short circuit current for low voltage circuit breakers and fuses. The equation is derived from Section 10.1.4.3 within IEEE/ANSI Std. C37.13-1990 and Section 3.41 in IEEE Std. 1015-1997.

(Eq. 1) unfused LVCB and MCCB: $MF_{UF} = \dfrac{1+e^{-\pi/X/Rcalc}}{1+e^{-\pi/X/Rtest}}$

(Eq. 2) $I_{Sym(Corrected)} = I_{Sym\ (CALC)} * MF_{UF}$

Where:

$I_{Sym\ (Corrected)}$ = symmetrical current corrected based on Calculated X/R versus the tested X/R
$I_{Sym\ (CALC)}$ = symmetrical short circuit current for the ½ cycle network at point of fault
X/R_{CALC} = calculated X/R ratio using the first cycle network at the point of fault
X/R_{TEST} = Breakers symmetrical ratings tested X/R ratio
MF_{UF} = the correction multiplying factor for unfused low voltage circuit breakers based on the Calculated versus Test X/R ratio; If the calculated X/R ratio is less than the Test X/R ratio, then the correction multiplying factor is equal to 1.

(Eq. 3) fused LVCB and fuses: $MF_{F} = \dfrac{(1+2*e^{-2*\pi/X/Rcalc})^{1/2}}{(1+2*e^{-2*\pi/X/Rtest})^{1/2}}$

(Eq. 4) $I_{Sym(Corrected)} = I_{Sym\ (CALC)} * MF_{F}$

Where:

MF_{F} = the correction multiplying factor for fused low voltage circuit breakers and fuse is based on the Calculated versus Test X/R ratio; If the calculated X/R ratio is less than the Test X/R ratio, then the correction multiplying factor is equal to 1.

Therefore, the corrected symmetrical short circuit calculated using Equation 2 or 4 is compared against the appropriate symmetrical rating of the low voltage circuit breaker based on calculated pre-fault voltage at the equipment.

7. Determination Of Short Circuit Current At Pressurizer Heater Power Panels

Pressurizer heater power panels PP-10, PP-11, PP-13, PP-14, PP-15, PP-16, PP-18, and PP-19 are modeled as "OFF" in the ETAP model. The fault current available at these power panels is determined using the pre-fault voltage and available short circuit current at the upstream switchgear with the cable impedance from the switchgear to the power panel using standard engineering formulas since there are no loads supplied by the power panels that contribute to the fault (e.g., motors). Fault impedance at the upstream switchgear is conservatively calculated from the maximum pre-fault voltage (Attachment E4) for any Case and the maximum available symmetrical fault current at the switchgear for any case using ohm's law.

The resistance and reactance values for the fault at the switchgear are calculated from the fault impedance at the switchgear and the X/R ratio taken from the ETAP report associated with the maximum available fault current using simple trigonometry.

The cable resistance is corrected from the 90 °C value to 25 °C for short circuit calculations consistent with the temperatures used in ETAP.

The cable resistance and reactance is calculated from cable size and impedance data using simple unit conversions.

The fault impedance to the power panels is calculated from the fault impedance at the switchgear and the cable impedance using simple vector addition.

The fault current and X/R ratio at the power panels is then calculated from the prefault voltage at the switchgear and the sum of the fault impedance at the switchgear and the cable impedance using ohm's law and a simple ratio.

The calculated values are carried at their full precision throughout the calculation and rounded only in the last step. The fault current is rounded up to the nearest ampere for and the X/R ratio is rounded to nearest tenth.

ACCEPTANCE CRITERIA

Acceptance Criteria for switchgear, MCCs and power panels: The calculated short circuit currents shall be less than the bus symmetrical and asymmetrical withstand ratings of the switchgear, MCCs and power panels. This is to ensure the switchgear, motor control centers and power panels are capable of performing their intended design and safety functions as required to meet PBNP GDC 39, FSAR Sections 8.2, 8.4 and 8.5, and the FPER.

Acceptance Criteria for short circuit ratings of high voltage circuit breakers: The calculated short circuit currents shall be less than the momentary and interrupting ratings (including application voltage) of the high voltage circuit breakers. This is to ensure the high voltage circuit breakers are capable of performing their intended safety functions as required to meet PBNP GDC 39, FSAR Sections 8.2 and 8.4, and the FPER.

Acceptance Criteria for short circuit ratings of low voltage circuit breakers: The calculated short circuit currents shall be less than the interrupting ratings (including application voltage) of the low voltage circuit breakers (based on appropriate short circuit rating considering pre-fault voltages applied). This is to ensure the low voltage circuit breakers are capable of performing their intended safety functions as required to meet PBNP GDC 39, FSAR Section 8.5 and the FPER.

Acceptance Criteria for short circuit ratings of fuses: The calculated short circuit currents shall be less than the interrupting rating (including application voltage) of the fuses (based on appropriate short circuit rating considering pre-fault voltages applied). This is to ensure the fuses are capable of performing their intended safety functions as required to meet PBNP GDC 39, FSAR Section 8.5 and the FPER.

ASSUMPTIONS

Unvalidated Assumptions-None

Validated Assumptions-None

RESULTS

The maximum switchyard voltage was adjusted until the highest voltage experienced by any 480 V switchgear, MCC, or power panel was equal to or less than 504 V in order to allow use of the 480 V interrupting ratings for the circuit breakers. The maximum allowable switchyard voltage was found to be slightly above 360.9 kV. Therefore, this calculation conservatively requires a limit on the maximum switchyard voltage to 360.5 kV.

Gas Turbine (G-05) Versus A-Train EDG (G-01 and G-02) Evaluation - The short circuit calculation is performed to establish the bounding short circuit configurations to provide the worst-case short circuit analysis. Based on the technical parameters of the gas turbine generator and the A-train EDG, it would be expected that the gas turbine would provide a higher short circuit contribution to the system than the A-train EDG. Therefore, the case of G-05 connected to Unit 1 and the case of G-05 connected to Unit 2 are evaluated against the case of G-01 connected to Unit 1 and G-02 connected to Unit 2 to ensure that the bounding plant configurations are analyzed. The results show, as expected, that the fault currents at the A-train 4.16 kV buses (1A-05 and 2A-05) are higher when G-05 is running and connected to the bus than when the EDG (G-01 or G-02) is running and connected to the bus. However, the results also show that fault currents at the 480 V buses are lower when G-05 is running than when the EDG (G-01 or G-02) is running. A further evaluation of the results shows that the pre-fault voltages on the 480V buses are higher. Therefore, even though the gas turbine generator provides a higher short circuit contribution to the system than the A-train EDGs, the increase in pre-fault voltage on the 480 V system has a greater effect than the increase in short circuit contribution from the gas turbine generator.

For the cases which model both units at 100% power, G-05 is importing VARs and pulling the voltage at the 13.8 kV, 4.16 kV and 480 V buses lower than if the gas turbine generator was "Off" as a result of the LVSATs being lightly loaded. In other cases the A-train EDGs (G-01 and G-02) are exporting VARs, which in turn increases the voltage on the 4.16kV and 480V buses. For these cases, the A-Train EDGs running, provides higher short circuit currents on the 480V switchgear due to the higher pre-fault voltages.

Therefore, a review of additional cases was performed to determine if additional plant configurations were required to be analyzed. The conclusion of this review was that the fault currents on the A-train buses calculated using the contribution from G-05 will bound those calculated using the EDG contribution for all plant alignments except one. For the A-train 480 V buses when the units are at 100% power with maximum 345 kV grid voltage and lightly loaded LVSATs, the A-train EDG paralleled with the system for testing and exporting maximum VARS, the EDG produces a higher fault current at the A-train 480 V buses. In this case the EDG drives the pre-fault voltage on the A-train 480 V buses, resulting in higher calculated fault currents on those buses.

In all of the other A-train cases where G-05 is running, it drives the bus voltage and provides a higher fault contribution than the A-train EDG would. Therefore, the bounding cases for the A-train short circuit currents have been identified and are evaluated in this calculation. Additional plant configurations need not be analyzed.

In conclusion, the fault currents on the A-train buses calculated using the contribution from G-05 will bound those calculated using the EDG contribution for all plant alignments except one. For the A-train 480 V buses when the units are at 100% power with maximum 345 kV grid voltage and lightly loaded LVSATs, the A-train EDG paralleled with the system for testing and exporting maximum VARS, the EDG produces a higher fault current at the A-train 480 V buses. In this case the EDG drives the pre-fault voltage on the A-train 480 V buses, resulting in higher calculated fault currents on those buses.

In all of the other A-train cases where G-05 is running, it drives the bus voltage and provides a higher fault contribution than the A-train EDG would. Therefore, the bounding cases for the A-train short circuit currents have been identified and are evaluated in this calculation. Additional plant configurations need not be analyzed. The following table is a summary of the buses that fail in one or more cases:

Master Failure List			
DeviceID	MCCB or Fuse Failures		
	Bus	Bus	Bus
1A-01	PP-7		
1A-02	PP-11		
B-81	PP-13		
	PP-18		
	PP-30		
	PP-33		
	PP-34		
	PP-67		

The short circuit current for the buses listed above was greater than the equipment rating for the worst-case plant configurations modeled. Therefore, Acceptance Criteria are not satisfied.

This potential issue needs to be evaluated and addressed as part of the EPU modifications.

Evaluation of the 480V switchgear voltage:

The maximum system voltages for 480V switchgear are below 500V which is the maximum value for which the 480V rating for DB breakers may be utilized. Therefore, the 480 V rating of the DB breakers is used. A review of the results for the breakers installed on 1B-01, 1B-02, 1B-03, 1B-04, 2B-01, 2B-02, 2B-03 and 2B-04 show that the calculated fault currents are less than the 480V interrupting rating for the circuit breakers. These circuit breakers meet acceptance criteria.

Switchgear B-07, B-08 and B-09 are within the appropriate voltage rating of 504V for MCCBs and 508 V for power circuit breakers. Therefore, the power circuit breakers at switchgear B-07, B-08 and B-09 will meet Acceptance Criteria and be capable of interrupting the available short-circuit current.

Switchgear B-507 is operating below its maximum voltage rating of 500 V. Therefore, the power circuit breakers at switchgear B-507 will meet Acceptance Criteria and be capable of interrupting the available short-circuit current.

Evaluation of DB breakers with discriminator disabled:

Circuit breakers 1B52-11B (1B-03), 1B52-14B (1B-03), 1B52-23A (1B-04), 1B52-23C (1B-04), 2B52-35C (2B-03), 2B52-38B (2B-03), 2B52-31B (2B-04), and 2B52-32C (2B-04) are DB-50 breakers installed on the safety related 480V switchgear with the discriminator circuit disabled, which results in a short circuit rating of 42kA with a maximum voltage rating of 630 V. A review of the results in Attachments E1 and F1 through F32 shows that the symmetrical short circuit duty for these breakers is less than the short circuit rating of 42 kA. Therefore, the power circuit breakers with their discriminators disabled will meet Acceptance Criteria and be capable of interrupting the available short-circuit current.

III. DEGRADED VOLTAGE ANALYSIS

III.1 PURPOSE AND SCOPE

III.1.01 PURPOSE

The purpose of this calculation is to determine the minimum voltage that must be maintained on the safeguards 4.16 kV buses to assure that all safety-related loads have adequate voltage to maintain continuous operation and starting capability during worst-case plant loading conditions. This calculation will determine the Technical Specification Allowable Values for TS 3.3.4 and the degraded voltage (DV) relays' voltage and time delay setpoints. The calculation will also determine the minimum 345 kV system voltage required to ensure the degraded voltage relays do not actuate (time out) during motor starting when offsite power is acceptable. The degraded voltage analysis ensures that all safety related equipment has sufficient voltage in order to be capable of performing its design and licensing functions during a loss of coolant accident and during normal plant operation by tripping offsite power when the voltage is unacceptable and maintaining offsite power when it is acceptable.

III.1.02 SCOPE

The scope of the degraded voltage analysis is limited to establishing the minimum voltage requirements for 4.16 kV safeguards buses 1A-05, 2A-05, 1A-06, and 2A-06 including all safety related loads fed downstream; ensure that the safeguards motors are capable of starting under minimum voltage conditions; establish the degraded voltage relay setpoints (voltage and time delay) for the relays identified in Table 1; and determine the minimum 345 kV system voltage required to maintain the safeguards bus voltage.

An additional set of static motor starting cases will also be generated for the RCP, Condensate, and Feed Water pump motors to ensure adequate voltage will be available with the A-01 and A-02 buses supplied through the X-02 transformers. The only purpose of the additional cases is to examine the terminal voltages for these specific motors. Evaluation of bus voltages and relay settings for the non-safety buses is outside the scope of this analysis.

III.1.03 TERMINOLOGY

a. **Dropout** occurs when the degraded voltage relay input voltage drops below a preset level. When dropout occurs, the relay starts to time out. After timing out, the relay output contacts change state.
b. **Pickup (or Reset)** occurs when relay input voltage returns to a preset level above the dropout setting to reset the relay. There is no time delay associated with pickup. The relay output contacts immediately change state when pickup occurs.
c. **Total Loop Error (TLE)** is the statistical combination of all uncertainties associated with the loop components. TLE is calculated using a combination of Square Root Sum of the Squares (SRSS) for independent and random errors, and algebraic methods for dependent non-random errors.
d. **Total Measurable Uncertainty (TMU)** is the statistical combination of uncertainties that are measurable during periodic (18 month) surveillance

testing of the DV relays. These are the uncertainties that can be 'reset' by returning the relay setpoint to its as-left calibration tolerance band.

e. **Safety Limit (SL)** is the minimum sustained voltage below which safeguards equipment may not satisfactorily operate to perform its design function.
f. **Analytical Limit (AL)** equals the Safety Limit plus an arbitrary margin assigned to allow for small future changes to the Safety Limit.
g. **Nominal Trip Setpoint (NTSP)** is the calculated minimum as-left setting that protects the Analytical Limit from being exceeded by accounting for all instrument uncertainties in the relay loop (at a 95% confidence level). ($NTSP_{DO}$ = Nominal Dropout Setpoint and $NTSP_{PU}$ = Nominal Pickup Setpoint)
h. **Allowable Value (AV)** is the calculated minimum as-found setting that protects the Analytical Limit from being exceeded by accounting for all unmeasurable uncertainties in the relay loop (at a 95% confidence level).
i. **Actual Trip Setpoint (ATSP)** is the ideal field setting in the calibration procedure. The ATSP equals the NTSP plus a field setting tolerance band. ($ATSP_{DO}$ = Actual Dropout Setpoint and $ATSP_{PU}$ = Actual Pickup Setpoint)

III.2 METHODOLOGY

The methodology used in this calculation section to determine the degraded voltage time delay with and without an SI is partially described in the Current Licensing Basis (CLB) for PBNP. The remainder of the methodology used in this calculation section is not described in the CLB for PBNP. The time delay relay settings determined using the methodology described in Section III.2.11 appear in Technical Specification 3.3.4 (Reference VII.8.01) and in SER 2007-0002 (Reference VII.8.23), and the SER contains portions of the methodology presented in that section.

The following steps develop the minimum required 4.16 kV safety related bus voltage to ensure all equipment remains above its minimum voltage requirements, determine the degraded voltage relay trip set points, and determine the minimum 345 kV system voltage to ensure the 4.16 kV system is maintained above the pickup setpoint of the degraded voltage relays. The following steps will be performed:

III.2.01 ESTABLISH AC ELECTRICAL DISTRIBUTION SYSTEM MODEL

The AC electrical distribution system model is developed in Calculation 2008-0025 (Reference VII.1.26). Calculation 2008-0025 contains the technical data, equipment demand factors, and operating (e.g. ON/OFF, brake horsepower, etc.) status for plant equipment from the 345 kV system through the 480 V system in ETAP (Reference VII.3.01). This ETAP model will be utilized to determine the minimum 4.16 kV system voltage required to ensure operation of all safety related equipment, perform motor starting analysis under minimum voltage conditions, and determine the minimum required 345 kV system voltage.

III.2.02 ESTABLISH PLANT OPERATING CONDITIONS (SCENARIOS/CASES)

The plant operating conditions are developed in Calculation 2008-0025 (Reference VII.1.26) and the worst-case conditions for the unit being evaluated are determined. The plant operating conditions being evaluated are consistent with plant operation, plant operating procedures, design basis events and licensing commitments to ensure the worst case conditions are evaluated for minimum voltage conditions. The following are the plant operating configurations to be evaluated for minimum voltage conditions.

Configuration	Unit 1 Mode	Unit 2 Mode	13.8 KV Alignment	HVSAT Out-of-Service	LVSAT Out-of Service	UAT Out-of-Service
Degraded Voltage Configurations:						
L1-1X2	Mode 3 – LOCA	Mode 1	H-01 to H-02	None	None	1X-02
L1-1X4	Mode 3 – LOCA	Mode 1	H-01 to H-03	None	1X-04	1X-02
L1-2X3	Mode 3 LOCA	Mode 1	All Tied Together	2X-03	None	1X-02
L2-2X2	Mode 1	Mode 3 – LOCA	H-01 to H-03	None	None	2X-02
L2-2X4	Mode 1	Mode 3 LOCA	H-01 to H-02	None	2X-04	2X-02
L2-1X3	Mode 1	Mode 3 – LOCA	All Tied Together	1X-03	None	2X-02

Configuration Descriptions:

Conditions Common to All LOCA Configurations: There are six configurations involving a large break LOCA (L1-1X2, L1-1X4, L1-2X3, L2-2X2, L2-2X4, L2-1X3). For all of these configurations, the gas turbine generator and the emergency diesel generators are OFF (the generators would be running – their output breakers remain open). A large break LOCA would have all safeguards loads operating at their maximum brake horsepower incuding containment spray pump motors, which start upon receipt of a high-high containment pressure signal [>25 PSI (Reference VII.7.06)].

Case L1-1X2: This case models Unit 1 in mode 3 due to a unit trip caused by a large break LOCA and Unit 2 in mode 1 at 100% power with 1X-02 out of service due to a failure. The 480 V loads supplied by transformers 1X-11 and 1X-12 are energized. However, all 4kV balance of plant motors will be off since these motors are stripped from buses 1A-01 and 1A-02 as part of the automatic bus transfer scheme associated with the loss of transformer 1X-02. This case is used to prove the worst-case loading configuration for Unit 1 safeguards buses is the L1-1X4 configuration.

Case L1-1X4: This case models Unit 1 in mode 3 due to a unit trip caused by a large break LOCA and Unit 2 in mode 1 at 100% power with 1X-04 out of service. The PBNP licensing basis does not require analysis of both transformers 1X-04 and 1X-02 out of service coincident with a LOCA. However, in order to provide conservative loading values for transformer 2X-04, transformers 1X-11 and 1X-12 are modeled as supplied by buses 1A-03 and 1A-04. This case is used in determining the worst-case loading configuration for Unit 1 safeguards buses, to determine the minimum 4.16 KV system voltage requirements and to evaluate motor starting at the minimum system voltage.

Case L1-2X3: This case models Unit 1 in mode 3 due to a unit trip caused by a large break LOCA and Unit 2 in mode 1 at 100% power with 2X-03 out of service. The PBNP licensing basis does not require analysis of both transformers 1X-02 and 2X-03 out of service coincident with a LOCA. However, in order to provide conservative loading values for transformers 1X-03 and 1X-04, transformers 1X-11 and 1X-12 are modeled as supplied by buses 1A-03 and 1A-04. This case is used in determining the worst-case loading configuration for Unit 1 safeguards buses, to determine the minimum 4.16 KV system voltage requirements and to evaluate motor starting at the minimum system voltage.

Case L2-2X2: This case models Unit 2 in mode 3 due to a unit trip caused by a large break LOCA and Unit 1 in mode 1 at 100% power with 2X-02 out of service due to a failure. The 480 V loads supplied by transformers 2X-11 and 2X-12 are energized. However, all 4kV balance of plant motors will be off since these motors are stripped from buses 2A-01 and 2A-02 as part of the automatic bus transfer scheme associated with the loss of transformer 2X-02. This case is used to prove the worst-case loading configuration for Unit 2 safeguards buses is the L2-2X4 configuration.

Case L2-2X4: This case models Unit 2 in mode 3 due to a unit trip caused by a large break LOCA and Unit 1 in mode 1 at 100% power with 2X-04 out of service. The PBNP licensing basis does not require analysis of both transformers 2X-04 and 2X-02 out of service coincident with a LOCA. However, in order to provide conservative loading values for transformer 1X-04, transformers 2X-11 and 2X-12 are modeled as supplied by buses 2A-03 and 2A-04. This case is used in determining the worst-case loading configuration for Unit 2 safeguards buses, to determine the minimum 4.16 KV system voltage requirements and to evaluate motor starting at the minimum system voltage.

Case L2-1X3: This case models Unit 2 in mode 3 due to a unit trip caused by a large break LOCA and Unit 1 in mode 1 at 100% power with 1X-03 out of service. The PBNP licensing basis does not require analysis of both transformers 2X-02 and 1X-03 out of service coincident with a LOCA. However, in order to provide conservative loading values for transformers 2X-03 and 2X-04, transformers 2X-11 and 2X-12 are modeled as supplied by buses 2A-03 and 2A-04. This case is used in determining the worst-case loading configuration for Unit 2 safeguards buses, to determine the minimum 4.16 KV system voltage requirements and to evaluate motor starting at the minimum system voltage.

III.2.03 ESTABLISH CABLE IMPEDANCE TEMPERATURE

The cable temperature at which the cable impedance is calculated for the degraded voltage analysis is developed in Calculation 2008-0025 (Reference VII.1.26). The cable impedance temperature utilized to perform the degraded voltage analysis is 90 degrees centigrade, which provides a conservative temperature to ensure the maximum voltage drop through cables is taken into account. The 90 degree centigrade temperature is conservative because a higher cable temperature will result in higher cable resistances, which will produce lower calculated voltages at the loads.

III.2.04 DETERMINE MINIMUM 4.16 KV SYSTEM VOLTAGE

The degraded voltage relays sense the minimum system voltage at 4.16 kV safety related Buses 1A-05 (Unit 1 A-Train), 1A-06 (Unit 1 B-Train), 2A-05 (Unit 2 A-Train), and 2A-06 (Unit 2 B-Train). Therefore, the minimum voltage at the 4.16 kV system is established at these four buses to ensure that all safety related equipment in the 4.16 kV and 480 V systems have sufficient voltage to perform their design function during a Design Basis Event (e.g. LOCA). This will establish the safety limit for each safety related 4.16 kV bus.

The minimum voltage is calculated by utilizing the ETAP load flow analysis module (Reference VII.3.01) and the AC Electrical System Model developed in Calculation 2008-0025 (Reference VII.1.26) to calculate the steady state voltage at each safety related component. Configuration L1-1X4 will be used to determine the minimum voltage (Safety Limit) for Buses 1A-05 (Unit 1 A-Train) and 1A-06 (Unit 1 B-Train); L2-2X4 will be used to determine the minimum voltage (Safety Limit) for buses 2A-05 (Unit 2 A-Train) and 2A-06 (Unit 2 B-Train). An iterative process is used to determine the minimum voltage by updating the associated generating category - voltage for the grid (345 kV system) until the minimum steady state voltage criteria for all safety related equipment supplied by the safeguards 4.16 kV buses is satisfied. Essentially, the 345 kV system voltage is reduced until the most limiting safety related component reaches its minimum allowable voltage or maximum allowable current. The Newton Raphson iterative technique is used to calculate the equipment voltages for each condition evaluated. The load flow study case and its associated options were developed in Calculation 2008-0025 for each plant operating condition evaluated. The appropriate generator category will be used for the associated bus being evaluated (U1A – MIN, U1B – MIN, U2A – MIN, and U2B – MIN).

III.2.05 MOTOR STARTING ANALYSIS AT SAFETY LIMIT VOLTAGE

The maximum loading conditions during a degraded voltage condition exist when it is coincident with a loss of coolant accident and the following signals are present: Safety Injection, Containment Isolation, Low Pressurizer Level and High Containment Pressure. The various signals actuate the safeguards logic and sequentially start the safety related equipment shown on Reference VII.5.01, unless the equipment was running prior to the safeguards actuation signals. Therefore, a motor starting analysis is required to demonstrate the safety related motors would start at minimum voltage conditions.

A series of dynamic motor starting analyses (study cases) are performed to demonstrate the adequacy of the minimum system voltage and the affects on the safety related electrical equipment. In a dynamic motor starting analysis, the starting motors are evaluated based on their design characteristics (speed vs. torque curves) to ensure that the safety related motors are capable of starting and the effects of the voltage dips on the 4.16 kV and 480 V systems are acceptable. The adequacy of the safety related equipment will be evaluated based on the motors starting sequence during a LOCA at the offsite grid voltage and configuration that determined the minimum safety limit as described in Section III.2.04.

The motor starting analyses are performed by utilizing the ETAP (Reference VII.3.01) motor acceleration analysis module using dynamic motor starting to demonstrate the ability of safeguards motors to start at the offsite grid voltage that determined the minimum safety limit voltage utilizing the AC Electrical System Model developed in Calculation 2008-0025 (Reference VII.1.26). The motor starting analysis will be performed for each plant safety related train at the offsite grid voltage that determined the minimum safety limit voltage calculated in Section III.2.04 with the same plant configuration (Configuration L1-1X4 for 1A-05 and 1A-06; Configuration L2-2X4 for 2A-05 and 2A-06).

The motor starting sequences (events) are developed to evaluate each individual starting sequence to ensure that each safety related motor is capable of starting under worst-case conditions during a loss of coolant accident. The following was taken into consideration for the motor starting sequence:

a. The containment spray pump (P-014) will start after a nominal 10.25 seconds delay following the receipt of a containment high-high pressure signal (Reference VII.1.26). Since the containment high-high pressure signal may be received any time during the event, the containment spray pump was considered to start simultaneously with each motor after 10.25 seconds. The earliest containment spray pump start occurs when the containment high-high pressure signal is received at t=0, and the pump starts 10.25 seconds later. Therefore, the containment spray pump could start simultaneously with any motor that starts later than 10.25 seconds into the event.
b. Service water pump and containment accident fan motors may be running prior to the start of the event. Therefore, in order to calculate worst case bus loading, these motors are modeled as running for sequence steps prior to their scheduled sequence start. This will provide worst-case starting conditions because the bus is at its maximum loading condition.
c. The uncertainty of the starting sequence is taken into consideration for each motor to evaluate the potential overlap. The worst-case sequence times are contained in Reference VII.1.26.
d. Only a single containment accident fan motor would start during the sequence because three of four accident fans are running during normal plant operations (Reference VII.4.29). Therefore, only a single accident fan motor is considered in development of the motor sequences.

The motor starting study case options are developed in Calculation 2008-0025 (Reference VII.1.26). The following motor starting sequence (events) will be utilized to perform the dynamic motor starting analysis:

Section III -- Degraded Voltage Analysis

Study Case: U1-LBA-A (Bus 1A-05) and U1-LBB-A (Bus 1A-06)

Time Sequence	Equipment
T = 0 sec	1P-015A, 1P-015B, 1CV-00112B, 1CV-00112C, 1CV-00313, 1RC-00427, 1SW-02907, 1SW-02908, 1SI-00852A, 1SI-00852B, FO-03930, FO-03931, SW-02816, SW-02817, SW-02927A, SW-02927B, SW-02930A, SW-02930B, SW-04478, and SW-04479
T=0 sec	1SI-00860A, 1SI-00860B, 1SI-00860C, and 1SI-00860D
T = 5.25 sec	1P-010A and 1P-010B
T = 10.14 sec	P-038A, P-038B, AF-04021, AF-04023, 1P-014A, & 1P-014B
Motors Running Throughout Event	P-032A, P-032B, P-032C, P-032D, P-032E, P-032F, 1W-001A1, 1W-001B1, 1W-001C1, and 1W-001D1
Total Simulation Time	16 seconds

Study Case: U1-LBA-B (Bus 1A-05) and U1-LBB-B (Bus 1A-06)

Time Sequence	Equipment
T = 0 sec	1P-015A, 1P-015B, 1CV-00112B, 1CV-00112C, 1CV-00313, 1RC-00427, 1SW-02907, 1SW-02908, 1SI-00852A, 1SI-00852B, FO-03930, FO-03931, SW-02816, SW-02817, SW-02927A, SW-02927B, SW-02930A, SW-02930B, SW-04478, and SW-04479
T= 4.77 sec	1SI-00860A, 1SI-00860B, 1SI-00860C, and 1SI-00860D
T = 5.5 sec	1P-010A and 1P-010B
T = 10.89 sec	P-038A, P-038B, AF-04021 and AF-04023
T = 15.02 sec	P-032A, P-032C, 1P-014A, & 1P-014B
Motors Running Throughout Event	P-032B, P-032D, P-032E, P-032F, 1W-001A1, 1W-001B1, 1W-001C1, and 1W-001D1
Total Simulation Time	21 seconds

Study Case: U1-LBA-C (Bus 1A-05) and U1-LBB-C (Bus 1A-06)

Time Sequence	Equipment
T = 0 sec	1P-015A, 1P-015B, 1CV-00112B, 1CV-00112C, 1CV-00313, 1RC-00427, 1SW-02907, 1SW-02908, 1SI-00852A, 1SI-00852B, FO-03930, FO-03931, SW-02816, SW-02817, SW-02927A, SW-02927B, SW-02930A, SW-02930B, SW-04478, and SW-04479
T = 5.5 sec	1P-010A and 1P-010B
T= 9.63 sec	1SI-00860A, 1SI-00860B, 1SI-00860C, and 1SI-00860D
T = 10.89 sec	P-038A, P-038B, AF-04021 and AF-04023
T = 16.02 sec	P-032A and P-032C
T = 19.88 sec	P-032B, 1P-014A, 1P-014B & P-032D
Motors Running Throughout Event	P-032E, P-032F, 1W-001A1, 1W-001B1, 1W-001C1, and 1W-001D1
Total Simulation Time	26 seconds

Study Case: U1-LBA-D (Bus 1A-05) and U1-LBB-D (Bus 1A-06)

Time Sequence	Equipment
T = 0 sec	1P-015A, 1P-015B, 1CV-00112B, 1CV-00112C, 1CV-00313, 1RC-00427, 1SW-02907, 1SW-02908, 1SI-00852A, 1SI-00852B, FO-03930, FO-03931, SW-02816, SW-02817, SW-02927A, SW-02927B, SW-02930A, SW-02930B, SW-04478, and SW-04479
T = 5.5 sec	1P-010A and 1P-010B
T = 10.5 sec	P-038A, P-038B, AF-04021 and AF-04023
T = 15.5 sec	P-032A and P-032C
T = 21.17 sec	P-032B and P-032D
T= 28.01 sec	1SI-00860A, 1SI-00860B, 1SI-00860C, and 1SI-00860D
T = 38.26 sec	1W-001A1 (-DA), 1W-001C1 (-DB), 1P-014A, & 1P-014B
Motors Running Throughout Event	P-032E, P-032F, 1W-001B1, 1W-001A1 (-DB), 1W-001C1 (-DA) and 1W-001D1
Total Simulation Time	60 seconds

Section III – Degraded Voltage Analysis

Study Case: U2_LBA-A (Bus 2A-05) and U2_LBB-A (Bus 2A-06)

Time Sequence	Equipment
T = 0 sec	2P-015A, 2P-015B, 2CV-00112B, 2CV-00112C, 2CV-00313, 2RC-00427, 2SW-02907, 2SW-02908, 2SI-00852A, 2SI-00852B, FO-03930, FO-03931, SW-02816, SW-02817, SW-02927A, SW-02927B, SW-02930A, SW-02930B, SW-04478, and SW-04479
T = 0 sec	2SI-00860A, 2SI-00860B, 2SI-00860C and 2SI-00860D
T = 5.25 sec	2P-010A and 2P-010B
T = 10.14 sec	P-038A, P-038B, AF-04020, AF-04022, 2P-014A, & 2P-014B
Motors Running Throughout Event	P-032A, P-032B, P-032C, P-032D, P-032E, P-032F, 2W-001A1, 2W-001B1, 2W-001C1, and 2W-001D1
Total Simulation Time	16 seconds

Study Case: U2_LBA-B (Buses 2A-05) and U2_LBB-B (Bus 2A-06)

Time Sequence	Equipment
T = 0 sec	2P-015A, 2P-015B, 2CV-00112B, 2CV-00112C, 2CV-00313, 2RC-00427, 2SW-02907, 2SW-02908, 2SI-00852A, 2SI-00852B, FO-03930, FO-03931, SW-02816, SW-02817, SW-02927A, SW-02927B, SW-02930A, SW-02930B, SW-04478, and SW-04479
T = 5.5 sec	2P-010A and 2P-010B
T = 9.63 sec	2SI-00860A, 2SI-00860B, 2SI-00860C and 2SI-00860D
T = 10.89 sec	P-038A, P-038B, AF-04020 and AF-04022
T = 19.88 sec	P-032B, P-032D, 2P-014A, & 2P-014B
Motors Running Throughout Event	P-032A, P-032C, P-032E, P-032F, 2W-001A1, 2W-001B1, 2W-001C1, and 2W-001D1
Total Simulation Time	25 seconds

Study Case: U2_LBA-C (Buses 2A-05) and U2_LBB-C (Bus 2A-06)

Time Sequence	Equipment
T = 0 sec	2P-015A, 2P-015B, 2CV-00112B, 2CV-00112C, 2CV-00313, 2RC-00427, 2SW-02907, 2SW-02908, 2SI-00852A, 2SI-00852B, FO-03930, FO-03931, SW-02816, SW-02817, SW-02927A, SW-02927B, SW-02930A, SW-02930B, SW-04478, and SW-04479
T = 5.5 sec	2P-010A and 2P-010B
T = 10.5 sec	P-038A, P-038B, AF-04020 and AF-04022
T = 14.74 sec	2SI-00860A, 2SI-00860B, 2SI-00860C and 2SI-00860D
T = 21.17 sec	P-032B & P-032D
T = 24.99 sec	P-032E, P-032F, 2P-014A, & 2P-014B
Motors Running Throughout Event	P-032A, P-032C, 2W-001A1, 2W-001B1, 2W-001C1, and 2W-001D1
Total Simulation Time	30 seconds

Study Case: U2_LBA-D (Bus 2A-05) and U2_LBB-D (Bus 2A-06)

Time Sequence	Equipment
T = 0 sec	2P-015A, 2P-015B, 2CV-00112B, 2CV-00112C, 2CV-00313, 2RC-00427, 2SW-02907, 2SW-02908, 2SI-00852A, 2SI-00852B, FO-03930, FO-03931, SW-02816, SW-02817, SW-02927A, SW-02927B, SW-02930A, SW-02930B, SW-04478, and SW-04479
T = 5.5 sec	2P-010A and 2P-010B
T = 10.5sec	P-038A, P-038B, AF-04020 and AF-04022
T = 20.5sec	P-032B and P-032D
T = 26.57 sec	P-032E and P-032F
T = 28.01 sec	2SI-00860A, 2SI-00860B, 2SI-00860C and 2SI-00860D
T = 38.26 sec	2W-001A1 (-DA), 2W-001C1 (-DB), 2P-014A, & 2P-014B
Motors Running Throughout Event	P-032A, P-032C, 2W-001B1, 2W-001C1 (-DA), 2W-001A1 (-DB), and 2W-001D1
Total Simulation Time	60 seconds

III.2.06 STATIC MOTOR STARTING ANALYSIS FOR 4 KV BALANCE OF PLANT MOTORS

A static starting analysis will be performed to verify adequate voltage will be supplied to the motor terminals of the Reactor Coolant Pumps (1P-001A/B, 2P-001A/B), Feed Water Pumps (1P-028A/B, 2P-028A/B), and Condensate Pumps (1P-025A/B, 2P-025A/B). The only purpose of this analysis is to examine the motor terminal voltages at these specific 4 kV motors.

For all of these motor starting cases, the model will be configured to simulate both units on-line with the main generator output breakers open. This configuration will provide conservative values for bus voltages as the bus loading will be greater than what would occur during a normal start-up and the main generators will not be providing voltage support to the X-02 transformers.

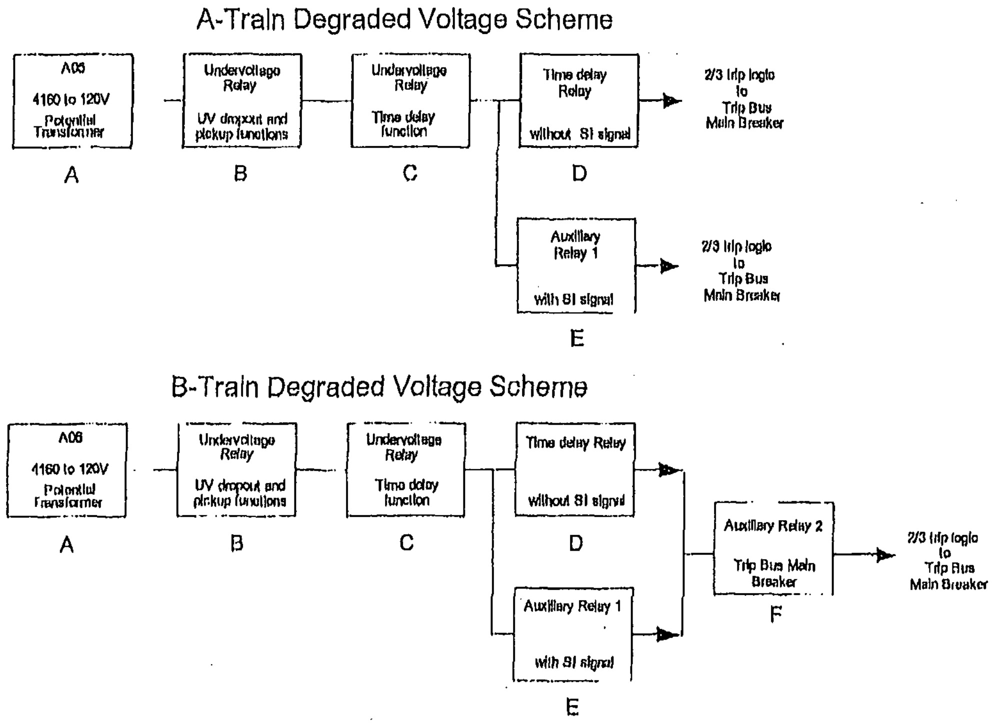
III.2.07 DETERMINE DEGRADED VOLTAGE RELAYS DROPOUT AND PICKUP VOLTAGE SETPOINTS

The degraded voltage relay dropout setpoint is established to ensure that the 4.16 kV safeguards buses are separated from offsite power prior to unsatisfactory operation of equipment (e.g., damage) or trip on overcurrent, which would prevent the equipment from being re-sequenced onto the emergency diesel generators. Additionally, the degraded voltage relay pickup setpoint is established to ensure that there is minimum differential between the dropout and pickup setpoints to reduce the probability of the safeguards buses separating from the preferred offsite power source during short-term undervoltage transients (e.g. motor starting) that recover to a voltage above the pickup setting.

The degraded voltage relays provide the means to transfer to emergency power (Emergency Diesel Generators) when offsite power is not sufficiently stable to allow safe unit operation. Therefore, the degraded voltage relays are provided in two-out-of-three logic to detect a sustained degraded voltage condition for each 4.16 kV safety related bus (References VII.5.02, VII.5.04, and VII.5.07). The degraded voltage relays ensure that the Engineering Safety Features (ESF) have sufficient voltage when supplied from offsite power to perform their function in a design basis accident. The degraded voltage relay dropout and pickup settings are categorized as Category A instrument setpoints per design guide DG-I01 (Reference VII.4.03) and will be calculated to a 95% probability at a 95% confidence level (95/95).

Figure 1 is a block diagram of the components that make-up each 4.16 kV safeguards bus degraded voltage protection loop on both units. There are two buses (A-train and B-train) per unit. There are three independent loops per bus that each supply a two out-of-three coincidence logic (twelve independent loops total). This section describes the dropout and pickup set points involving blocks A and B.

Figure 1: Degraded Voltage Protection Loop Block Diagram:



Section III – Degraded Voltage Analysis

Table 1: Degraded Voltage Loop Component Information

Block Diagram Component	Mfr / Model	Component ID			
		1-A05	1-A06	2-A05	2-A06
A - Potential XFMR	West 1483798 or GE Type JVM-3	No ID	No ID	No ID	No ID
B & C - UV Relay	ABB 27N 411T4175-HF-L	PB1 274/A05 PB1 275/A05 PB1 276/A05	PB1 274/A06 PB1 275/A06 PB1 276/A06	PB2 274/A05 PB2 275/A05 PB2 276/A05	PB2 274/A06 PB2 275/A06 PB2 276/A06
D - TD Relay (no SI signal present)	Agastat ETR 14D3D004 or 14D3D003	PB1 TDRA/A05 PB1 TDRB/A05 PB1 TDRC/A05	PB1 62-1/A-06 PB1 62-2/A-06 PB1 62-3/A-06	PB2 TDRA/A05 PB2 TDRB/A05 PB2 TDRC/A05	PB2 62-1/A-06 PB2 62-2/A-06 PB2 62-3/A-06
E Aux Relay 1 (SI signal present)	Westinghouse NBFD65NR	PB1 274X/A05 PB1 275X/A05 PB1 276X/A05	PB1 274X/A06 PB1 275X/A06 PB1 276X/A06	PB2 274X/A05 PB2 275X/A05 PB2 276X/A05	PB2 274X/A06 PB2 275X/A06 PB2 276X/A06
F - Aux Relay 2	ABB RXMA-2	N/A	PB1 62-1X1/A06 PB1 62-2X1/A06	N/A	PB2 62-1X1/A06 PB2 62-2X1/A06

Figure 2 illustrates the setpoint determination sequence (numbered circles) and the relationship between the Safety Limit (SL), Analytical Limit (AL), Nominal Trip Setpoint (NTSP), Allowable Value (AV) and the Actual Trip Setpoint (ATSP) for both the degraded voltage relay dropout and pickup setpoints.

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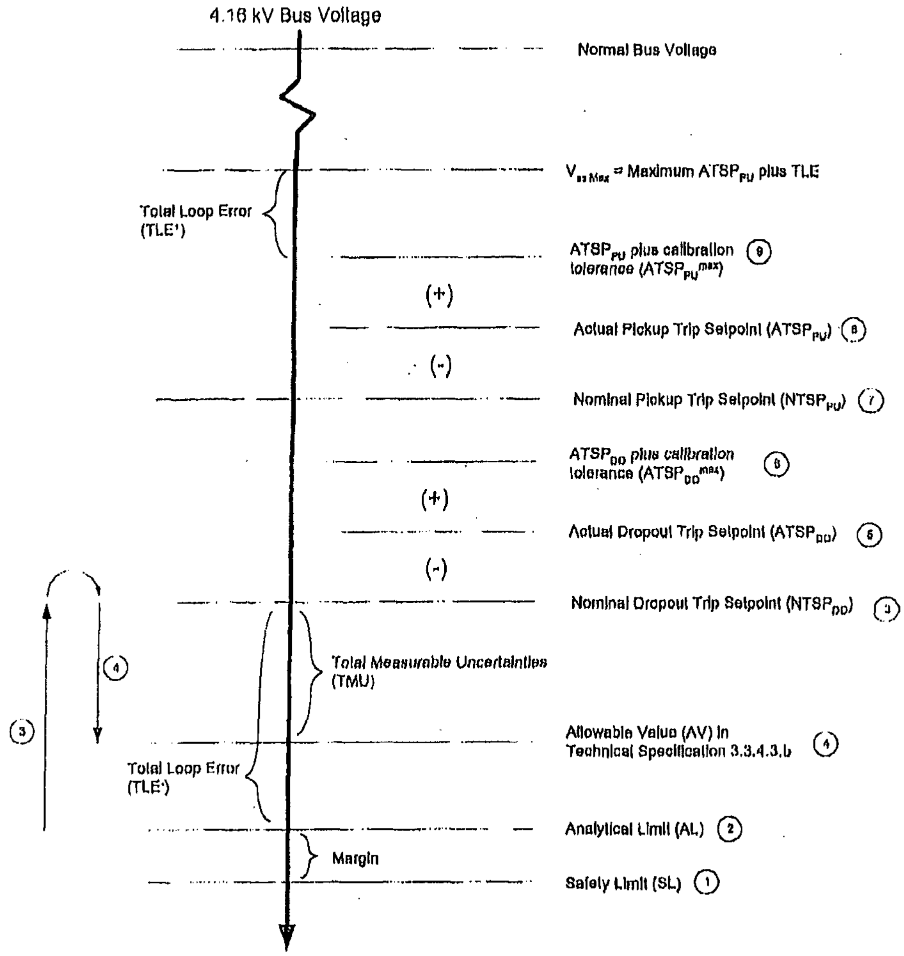
Figure 2: Dropout and Pickup Setpoint Diagram



Note: The ATSP and NTSP values shown on this Figure will be determined at the low voltage (120V) signal level in this calculation, rather that at the high voltage (4160V) signal level.

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The methodology of this calculation is based on the guidance of Design Guide DG-I01 "Instrument Setpoint Methodology" (Reference VII.4.03). The sections below are an outline of the calculation approach to determine the appropriate degraded voltage relay pickup and dropout setpoints. Note: Rounding the setpoints is performed by round-up on lower limits and rounding down on upper limits for as-left calibration settings. This ensures the safety limit is maintained.

III.2.07.1 The voltage sensing loop error contributors associated with blocks A and B in Figure 1 are identified based on the guidance within design guide DG-101 (Reference VII.4.03). The following will determine whether each error contributor is applicable, random, nonrandom, independent, and/or a direction bias. With the exception of the Block A PT correction factor, the error contributors will be expressed in <u>percent of relay setting</u> (rather than in percent of relay setting span), to be consistent with the manufacturer's published relay accuracy (see Reference VII.4.04):

a. Accuracy: The manufacturer gives the relay setting accuracy as repeatability. Because the relay setting for the dropout and pickup are each approached from only one direction, linearity and hysteresis are not included in the relay accuracy term. Note that when the drift is determined by as-left / as-found calibration data, relay accuracy is included as part of the drift term.

b. Primary Element Accuracy (Potential Transformer):The degraded voltage relays sense a voltage between 0 – 150Vac, therefore it is necessary to a have a potential transformer (PT) to convert a high voltage signal to a low voltage signal. As described in IEEE Std. C57.13-1993 (Reference VII.2.06), the voltage on the secondary side of a potential transformer is a function of the burden (load) on the PT and is described by the PT's accuracy class or provided by the manufacturer. Because a PT has a fixed turn's ratio, the PT error is limited to the correction applied to the turns ratio as a result of the secondary side burden. This error is a bias, because the burden shifts the PT output in only one direction for a given burden. The error of the PT will be expressed as PT^- for the largest error in the negative direction and PT^+ for the largest error in the positive direction. The error of the PT will be accounted for in the conversion from a high voltage signal to a low voltage signal in Step III.2.07.6 below and from a low voltage signal to a high voltage signal in Steps III.2.07.13 and III.2.07.14 below. The PT error is applied to the signal before applying the total loop error because the PT error is based on the turns ratio of the transformer and connected burden, and is unrelated to the error of the degraded voltage relays themselves.

c. Drift: Relay setpoint drift applies as a random uncertainty for both dropout and pickup settings. Drift can be calculated or given by the manufacturer. No manufacturer drift value is available, but relay calibrations performed since the mid-1990's (when the relays were installed) provide as-left / as-found data that can be used to calculate the drift using statistical methods described in Appendix H of DG-I01 (Reference VII.4.03). See Step III.2.07.2 below for more explanation of this method of determining drift.

d. M&TE: The manufacturer of the M&TE provides an uncertainty associated with frequency of calibration of the M&TE. The uncertainty of the M&TE is random and independent in consideration of the degraded voltage relay setpoint. However, when relay setting drift is determined using as-left/as-found calibration data, M&TE accuracy is included as part of the calculated drift term, and does not need to be accounted for separately (as long as the M&TE uncertainty is less than or equal to the M&TE used to perform the calibrations).

e. Setting Tolerance: The setting tolerance establishes a sufficient range to allow the technician to set the relay. Setting tolerance is expressed as a random (±) value around an ideal setting, although the tolerance can also be asymmetric (e.g., +2, -0). The tolerance range is established based on the device accuracy, MT&E accuracy used to calibrate the relays, the limitations of the technician in adjusting the device, and the need to minimize calibration and testing time. When drift is determined by as-left/as-found statistical methods, setting tolerance is treated as a separate random contributor to total loop error.

f. Power Supply Effect: The power supply effect is the effect of control voltage variations on the relay settings. The manufacturer provides an uncertainty of the relays due to control voltage. The degraded voltage relays use 125 V_{DC} control power from DC buses that are normally supplied by voltage-regulated battery chargers. This effect is given a value by the relay manufacturer separate from the relay accuracy and is considered random and independent from other error terms. As-left/as-found calibration data will account for some of this effect, however the temperature recorded during performance of calibrations does not cover the complete range of operation. Therefore, it is conservative to apply the full power supply effect to the overall relay uncertainty in addition to the drift tolerance.

g. Temperature Effect: The manufacturer provides an uncertainty of the relays due to temperature. This effect is assigned a value by the relay manufacturer separate from relay accuracy and is considered random and independent from other error terms. Similar to control voltage, as-left/as-found calibration data will account for some of this effect, however the temperature recorded during performance of calibrations does not cover the complete range of operation. Therefore, it is conservative to apply the full temperature effect to the overall relay uncertainty separate from the drift tolerance.

h. Humidity Effect: There is no uncertainty due to humidity changes provided by the relay manufacturer. The relays are rated over a temperature range of +10°C to +40°C (+50°F to +104°F) and have performed well under varying humidity conditions in the switchgear rooms for 10 years. Since no separate term for humidity effects is provided, these effects are taken to be negligible (essentially included in the overall accuracy for the relay) as described in DG-I01 (Reference VII.4.03). Therefore, no separate uncertainty due to humidity is considered in the total relay error.

i. Radiation Effect: The relays are located in plant areas (control building and diesel generator building) that will not experience any significant radiation exposure greater than background, even under accident conditions. Therefore, no radiation effect is considered in the total relay error.

j. Seismic or Vibration Effect: There is no uncertainty due to seismic or vibration effect provided by the relay manufacturer. Per reference VII.4.04, the Model 27N relay is a solid-state device rated at more than 6g ZPA biaxial broadband multi-frequency vibration without damage or malfunction, per ANSI C37.98-1978. Therefore, no additional uncertainty is required for the relay for seismic conditions when maintained within capability.

III.2.07.2 As-found/as-left calibration data will be statistically analyzed to establish the drift error on the degraded voltage relays. The general approach in performing a statistical analysis of the data is provided in Appendix H of Design Guide DG-I01 (Reference VII.4.03). The following is a summary of the steps performed in the statistical analysis:

a. As-left and as-found values for the degraded voltage relay dropout settings were compiled from historical plant relay calibration data collected between 1996 and 2005. The raw data for each of the twelve degraded voltage relays were tabulated in Attachment A, including as-left and as-found dropout values and as-left and as-found dates.

b. From the dropout values and dates, the number of days between calibrations and the measured drift over the interval was determined on the spreadsheet. To make the sample size representative of the nominal 18-month calibration interval, only those as-left/as-found pairings that were measured within ± 25% of 18 months (between 400 and 675 days apart) were analyzed.

c. Several calibrations were performed with M&TE that was less accurate than the M&TE required by the calibration procedure (This issue was documented in AR00426804). These readings were discarded from the final sample set.

d. From the population of as-left/as-found pairings that were suitable for analysis, the standard deviation was calculated using the Excel STDEV function.

e. The standard deviation was then multiplied by a factor based on the sample size to determine a 95% confidence level drift value.

f. DG-I01 provides the method of identifying and removing "outliers" from the sample population.

g. The data set was tested for "normalcy" by determining skewness and kurtosis using the procedure in DG-I01 Appendix H.

III.2.07.3 The total loop error (TLE) includes all relay uncertainties (except the PT ratio correction) and is determined in accordance with the requirements of Design Guide DG-I01 (Reference VII.4.03). The setpoint methodology at PBNP utilizes a combination of the straight sum and the square root sum of the square (SRSS) plus algebraic approaches. The error effects are evaluated based on known behavior and are characterized as independent, dependent, random or non-random. The random elements of uncertainty are combined by SRSS, and any non-random uncertainties (commonly known as a bias) are added algebraically (straight sum) to the SRSS result according to sign. The uncertainty equation for each instrument is based on the characteristics of each applicable element of uncertainty. Therefore, the following general equation is utilized to calculate the positive (TLE^+) and negative (TLE^-) total loop uncertainty and is developed in design guide DG-I01.

(Eq. 1) $$TLE = \pm\left[A^2 + B^2 + (C+D)^2\right]^{1/2} \pm \sum|X| + \sum Y - \sum Z$$

Where:

A, B =	Independent and Random uncertainty errors
C, D =	Dependent and Random uncertainty errors
X =	Non-random error with unknown sign
Y =	Non-random positive bias
Z =	Non-random negative bias

III.2.07.4 The total measurable uncertainty (TMU) is determined similarly to TLE, but is limited to those errors that are included in the portion of the loop that is measured during the calibration of the instruments/relays. The TMU is utilized to establish the Technical Specification value (Allowable Value) for the degraded voltage relays by "backing off" of the nominal trip setpoint (NTSP). Therefore, the following equation is utilized to calculate the measurable total loop uncertainty and is developed based on Design Guide DG-I01.

$$(\text{Eq. 2})\ \text{TMU} = \pm\left[E^2 + F^2 + (G+H)^2\right]^{1/2} \pm \sum|U| + \sum V - \sum W$$

Where:

E, F =	Independent and Random uncertainty errors included in Calibration (Measurable error)
G, H =	Dependent and Random uncertainty errors included in Calibration (Measurable error)
U =	Non-random error with unknown sign included in Calibration (Measurable error)
V =	Non-random positive bias included in Calibration (Measurable error)
W =	Non-random negative bias included in Calibration (Measurable error)

III.2.07.5 The degraded voltage Safety Limit (SL) is determined for each safety related 4.16 kV bus in Sections III.2.04 and III.2.05. The SL is established on a base voltage relative to the 4.16 kV system (See Figure 2, Item 1). The degraded voltage Analytical Limit (AL) is established based on the most limiting SL for the safety related 4.16 kV buses. This provides a common AL for each safety related 4.16 kV bus in which the degraded voltage relays setpoints will be determined and will establish a single Technical Specification Allowable Value for the 4.16 kV system. (See Figure 2, Item 2).

III.2.07.6 The degraded voltage relays require an input voltage of 0 – 150 V_{AC}. Therefore, a potential transformer (PT) is used to convert the 4.16kV nominal bus voltage signal to a low voltage (120V nominal) signal using a PT with a nominal 35:1 turns ratio. The low voltage signal is determined by dividing the Analytical Limit by the nominal turns ratio of the PT (n) and by the ratio correction factor in the negative direction of the PT (PT^-). The low voltage signal corresponding to the Analytical Limit will be defined as V_{AL} and is determined by the following equation:

$$(\text{Eq. 3})\ V_{AL} = \frac{AL}{n * PT^-}$$

III.2.07.7 The degraded voltage relay's dropout setpoint is determined to ensure the 4.16 kV system voltage does not drop below the minimum allowed voltage established in Sections III.2.04 and III.2.05 (the Analytical Limit). The Nominal Trip Setpoint ($NTSP_{DO}$) for the degraded voltage relay dropout set point is calculated to ensure the Analytical Limit (AL) is protected. The difference between the $NTSP_{DO}$ and AL accounts for all uncertainties associated with worst-case conditions (i.e. the TLE⁻). The $NTSP_{DO}$ is calculated based on design guide DG-I01 (Reference VII.4.03) as follows (See Figure 2, Item 3):

$$\text{(Eq. 4)}\quad NTSP_{DO} = \frac{V_{AL}}{1 - TLE^{-}}$$

Where:

$NTSP_{DO}$:	Degraded Voltage relays nominal dropout setpoint
V_{AL}:	low voltage signal's Analytical Limit on secondary side of PT
TLE:	Negative total loop error (in % of setting)

III.2.07.8 The Allowable Value (AV) to be placed in TS 3.3.4.3.b is determined to ensure sufficient margin exists between the degraded voltage relay dropout Nominal Trip Setpoint ($NTSP_{DO}$) and the Analytical Limit (AL) to account for instrument uncertainties that are either not present or are not measured during periodic testing. The AV establishes the 4.16 kV degraded voltage Technical Specification limit for the degraded voltage dropout setting, and is used as the basis for determining that the degraded voltage relay setting is operable. The AV is calculated based on Design Guide DG-I01 (Reference VII.4.03) as follows (See Figure 2, Item 4):

$$\text{(Eq. 5)}\quad AV = NTSP_{DO} - TMU * NTSP_{DO}$$

Where:

AV:	Technical Specification Allowable Value limiting dropout setpoint found during calibration of degraded voltage relays
$NTSP_{DO}$:	Degraded Voltage relay nominal dropout setpoint
TMU:	Total Measurable error – total instrument error for calibration conditions of those uncertainties that can be measured during performance of the surveillance

Note: The Allowable Value (AV) also provides the minimum as-found setting for the Block B relay based on TMU. This as-found limit ensures that the Block B Safety Limit (SL) is protected and that the relay is exhibiting a 95/95 level of response.

III.2.07.9 The degraded voltage relay setting tolerance is established to allow an acceptable setpoint range for technicians to set the relays. The setting tolerance will be determined to be equal to or greater than the SRSS of accuracy of the degraded voltage relays and the M&TE accuracy. This will ensure that the setting tolerance is large enough to allow the trip setpoints to be easily adjusted between the limits. This setting tolerance will apply to both the dropout and pickup setting of the degraded voltage relays. The following equation establishes the setting tolerance:

(Eq. 6) $ST = \pm\sqrt{a^2 + m^2}$

Where:

ST:	Allowable setting tolerance of the relays
a:	repeatability accuracy at constant temperature and control voltage of the degraded voltage relays
m:	M&TE error for equipment used to calibrate the relays

III.2.07.10 The degraded voltage relays dropout Actual Trip Setpoint ($ATSP_{DO}$) is determined by adding the $NTSP_{DO}$ and ST. This establishes the $ATSP_{DO}$ and provides a positive and negative range for calibration of the relays to ensure the as-left setting will always be greater than or equal to $NTSP_{DO}$. (See Figure 2, Item 6)

(Eq. 7) $ATSP_{DO} = NTSP_{DO} + ST * NTSP_{DO}$

III.2.07.11 The degraded voltage relays pickup Nominal Trip Setpoint ($NTSP_{PU}$) will be set at 0.5% above the dropout $NTSP_{DO}$, which is the minimum pickup/dropout differential allowed by the relay design (Reference VII.4.04). The differential between the dropout and pickup settings reduces the probability of safeguards bus separation from the preferred offsite power source during short-term undervoltage transients that recover above the pickup setting. Therefore, the $NTSP_{PU}$ is determined by the following equation (See Figure 2, Item 7):

(Eq. 8) $NTSP_{PU} = 1.005 * NTSP_{DO}$

III.2.07.12 The degraded voltage relay pickup Actual Trip Setpoint ($ATSP_{PU}$) is determined by adding the $NTSP_{PU}$ and ST. This establishes the $ATSP_{PU}$ and provides a positive and negative range for calibration of the relays to ensure the $NTSP_{PU}$ is maintained above the AV. Additionally, this will establish the maximum allowable $ATSP_{PU}$ based on the allowable setting tolerance to evaluate the minimum required 345 kV system voltage. (See Figure 2, Item 8)

(Eq. 9) $ATSP_{PU} = NTSP_{PU} + ST * NTSP_{PU}$

III.2.07.13 The maximum degraded voltage relay pickup actuation, including the total loop error, is determined by adding the TLE^+ to the maximum allowable $ATSP_{PU}$. The maximum degraded voltage relay pickup actuation is determined to establish the minimum allowed steady state 4.16 kV system voltage to ensure the degraded voltage relays will recover to a voltage greater than the pickup setting to reduce the probability of safeguards bus separation from preferred offsite power source during short term undervoltage transients. This minimum allowable steady state 4.16 kV system voltage will be utilized to determine the minimum required 345 kV system voltage that must be maintained (Section III.2.07.15). The low voltage signal will be converted back to a high voltage signal by multiplying the low voltage by the turns ratio (n) of the PT and by the ratio correction factor in the positive direction of the PT (PT^+). Therefore the maximum actuation of the degraded voltage relay pickup is determined by the following equation (See Figure 2, Item 9):

(Eq. 10a)
$$ATSP_{PU}^{MAX} = ATSP_{PU} + ATSP_{PU} * ST$$
$$V_{ss\,Max} = \left(ATSP_{PU}^{Max} + ATSP_{PU}^{Max} * TLE^+\right) * \left(n * PT^+\right)$$

III.2.07.14 The maximum degraded voltage relay dropout actuation, including the total loop error, is determined by adding the TLE^+ to the maximum allowable $ATSP_{DO}$. The maximum degraded voltage relay dropout actuation is determined to establish the maximum 4.16 kV system voltage in which the degraded voltage relays would reach their dropout voltage setpoint and begin the time delay. This is utilized in the motor starting analysis to determine the amount of time the degraded voltage relays are below the dropout setting and the amount of time to reach above the pickup setting during motor starting. Therefore, the maximum actuation of the degraded voltage relay dropout is determined by the following equation (See Figure 2, Item 8):

(Eq. 10b)
$$ATSP_{DO}^{MAX} = ATSP_{DO} + ATSP_{DO} * ST$$
$$V_{DO\,Max} = \left(ATSP_{DO}^{Max} + ATSP_{DO}^{Max} * TLE^+\right) * \left(n * PT^+\right)$$

III.2.07.15 The degraded voltage relay dropout Maximum As-found Value (MAF_{DO}^{MAX}) is the maximum acceptable as-found value during relay calibration above the Block B degraded voltage dropout maximum actual trip setpoint ($ATSP_{DO}^{MAX}$). This tolerance accounts for instrument uncertainties that are present and can be measured during periodic testing. The as-found limit ensures that the Block B relay is exhibiting a 95/95 level of response and is consistent with the setpoint methodology. The MAF_{DO}^{MAX} is calculated based on the guidance within design guide DG-I01 (Reference VII.4.03) as follows:

(Eq. 10c) $MAF_{DO}^{MAX} = ATSP_{DO}^{MAX} + TMU*ATSP_{DO}^{MAX}$

Where:

MAF_{DO}^{MAX} = Maximum As-Found value for Block B degraded voltage relay dropout.

TMU = Total Measurable error – total instrument error for calibration conditions of those uncertainties that can be measured during performance of the surveillance. The TMU is applied to the as-left tolerance limit of interest ($ATSP_{DO}^{MAX}$) consistent with other parts of this calculation, in which the error/uncertainty is based on a percent of the as-left calibrated value.

III.2.07.16 The degraded voltage relay pickup Minimum As-found Value (MAF_{PU}^{MIN}) is the minimum acceptable value during relay calibration below the Block B degraded voltage *pickup nominal trip setpoint* ($NTSP_{PU}$). *This* tolerance accounts for instrument uncertainties that are present and can be measured during periodic testing. The as-found limit ensures that the Block B relay is exhibiting a 95/95 level of response and is consistent with the setpoint methodology. The MAF_{PU}^{MIN} is calculated based on the guidance within design guide DG-I01 (Reference VII.4.03) as follows:

(Eq. 10d) $MAF_{PU}^{MIN} = NTSP_{PU} - TMU * NTSP_{PU}$

Where:

MAF_{PU}^{MIN} = Minimum As-Found value for Block B degraded voltage relay pickup.

TMU = Total Measurable error – total instrument error for calibration conditions of those uncertainties that can be measured during performance of the surveillance. The TMU is applied to the as-left tolerance limit of interest ($NTSP_{PU}$) consistent with other parts of this calculation, in which the error/uncertainty is based on a percent of the as-left calibrated value.

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III.2.07.17 The degraded voltage relay pickup Maximum As-found Value (MAF_{PU}^{MAX}) is the maximum acceptable as-found value during relay calibration above the Block B degraded voltage pickup maximum actual trip setpoint ($ATSP_{PU}^{MAX}$). This tolerance accounts for instrument uncertainties that are present and can be measured during periodic testing. The as-found limit ensures that the Block B relay is exhibiting a 95/95 level of response and is consistent with the setpoint methodology. The MAF_{PU}^{MAX} is calculated based on the guidance within design guide DG-J01 (Reference VII.4.03) as follows:

(Eq. 10e) $MAF_{PU}^{MAX} = ATSP_{PU}^{MAX} + TMU * ATSP_{PU}^{MAX}$

Where:

MAF_{PU}^{MAX} = Maximum As-Found value for Block B degraded voltage relay pickup.

TMU = Total Measurable error -- total instrument error for calibration conditions of those uncertainties that can be measured during performance of the surveillance. The TMU is applied to the as-left tolerance limit of interest ($ATSP_{PU}^{MAX}$) consistent with other parts of this calculation, in which the error/uncertainty is based on a percent of the as-left calibrated value.

III.2.08 DETERMINING MINIMUM STEADY STATE 345 KV SYSTEM VOLTAGE REQUIREMENTS

A minimum 345 kV steady state system voltage is determined to ensure the degraded voltage relays will recover to a voltage greater than the pickup setting prior to the relay timing out to reduce the probability of safety related buses separation from the preferred offsite power source during short term undervoltage transients (e.g., motor starting). Therefore, the minimum voltage on the 345 kV system is established to be greater than the $ATSP_{PU}$ of the degraded voltage relays plus total loop error (when converted to an equivalent high voltage signal) and is determined as $V_{ss\,Max}$ by Section III.2.07.13.

The minimum 345 kV system voltage is calculated utilizing ETAP load flow analysis module (Reference VII.3.01) to calculate the voltage at the safety related 4.16 kV buses for each unit utilizing the AC Electrical System Model developed in Calculation 2008-0025 (Reference VII.1.26). As discussed in the case descriptions above, the configuration of the plant during a unit trip with LOCA in one unit with the other unit in mode 1 (100% power) provides the worst-case loading on the high and low voltage station auxiliary transformers (1X-03 and 1X-04 or 2X-03 and 2X-04). This will provide the worst-case minimum 345 kV system voltage to ensure the 4.16 kV safety related buses are greater than the maximum degraded voltage pickup ($V_{SS\,Max}$). Study Case U1-MinV and configuration L1-1X4 will be used to determine the minimum 345 kV system voltage based on Buses 1A-05 (Unit 1 A-train) and 1A-06 (Unit 1 B-train); study case U2-MinV and configuration L2-2X4 will be used to determine the minimum 345 kV system voltage for Buses 2A-05 (Unit 2 A-train) and 2A-06 (Unit 2 B-train) when both HVSATs are in service. Configurations L1-2X3 and L2-1X3 will be used determine the minimum 345 kV system voltage for Unit 1 and Unit 2 respectively when only one HVSAT is in service.

An iterative process will determine the minimum voltage by updating the associated generating category - voltage for the Grid (345 kV system) until a voltage equal to or slightly greater than $V_{ss\,Max}$ is obtained on either 4.16 kV safety related bus for the unit being evaluated. The Newton Raphson iterative technique is used to calculate the equipment voltages for each condition evaluated. The load flow study case and its associated options were developed in Calculation 2008-0025 for each plant operating condition evaluated. The generator category (U1 Min Volt and U2 Min Volt) will be used to establish the worst-case minimum 345 kV system voltage for each operating unit (Unit 1 and Unit 2). The case resulting in the highest required switchyard voltage will provide the minimum allowable 345 kV system voltage to ensure the steady state 4 kV voltage is greater than the maximum reset voltage for the degraded voltage relays.

III.2.09 MOTOR STARTING ANALYSIS AT MINIMUM 345 KV SYSTEM VOLTAGE

A dynamic motor starting analysis is performed to ensure that the degraded voltage relays will not prematurely trip during safeguards motor starts with a loss of coolant accident at the minimum 345 kV system condition determined in Section III.2.08. The minimum 345 kV system voltage may be adjusted, as necessary, to ensure the bus voltage recovers above the degraded voltage maximum reset after motor starts. Additionally, the motor starting analysis is utilized to determine the duration of voltage dips below the maximum actuation setpoint. These durations will then be used to verify the time delay is set long enough to ensure sufficient time for the bus voltage to recover (prior to relay timing out) without separating from preferred offsite power.

The motor starting analyses are performed by utilizing ETAP (Reference VII.3.01) motor acceleration analysis module using dynamic motor starting to determine the ability of safeguards motors to start at the minimum system voltage utilizing the AC Electrical System Model developed in Calculation 2008-0025 (Reference VII.1.01).

The motor starting sequences (events) are developed to evaluate each individual starting sequence to ensure that each safety related motor is capable of starting under worst-case conditions during a loss of coolant accident. The following was taken into consideration for the motor starting sequence:

1. The starting sequence for each safeguards motor is evaluated at its nominal start time in the sequence interval. A comparison of the starting sequence with respect to motor starting (acceleration) will be performed and if the total starting (acceleration) time of the safeguards motor is greater than the minimum difference between motor sequence steps, additional starting analysis will be performed to evaluate the overlap of the motor starts.
2. Only a single containment accident fan motor would start during the sequence because three of the four accident fans are running during plant operations (Reference VII.4.29). Therefore, only a single containment accident fan motor start is considered in development of the motor starting sequences.
3. Containment spray pump (P-014) is not modeled to start for these study cases since the limiting motor start is the SI pump motor. In these cases, the containment spray pump is modeled as already running, thus providing conservative bus loading and voltages for the safety buses during the SI pump start.

The motor starting study case options are developed in Calculation 2008-0025 (Reference VII.1.26). The following motor starting sequence (events) will be utilized to perform the dynamic motor starting analysis:

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Study Case: U1-TD-A

Time Sequence	Equipment
T = 0 sec	1P-015A, 1P-015B, 1CV-00112B, 1CV-00112C, 1CV-00313, 1RC-00427, 1SW-02907, 1SW-02908, 1SI-00852A, 1SI-00852B, FO-03930, FO-03931, SW-02816, SW-02817, SW-02927A, SW-02927B, SW-02930A, SW-02930B, SW-04478, and SW-04479
T = 5.5 sec	1P-010A and 1P-010B
T = 10.5 sec	P-038A, P-038B, AF-04021 and AF-04023
T = 15.5 sec	P-032A and P-032C
T = 20.5 sec	P-032B and P-032D
T = 39.4 sec	1W-001A1
Motors Running Throughout Event	P-032E, P-032F, 1W-001B1, 1W-001C1 and 1W-001D1
Total Simulation Time	60 seconds

Study Case: U1-TD-B

Time Sequence	Equipment
T = 0 sec	1P-015A, 1P-015B, 1CV-00112B, 1CV-00112C, 1CV-00313, 1RC-00427, 1SW-02907, 1SW-02908, 1SI-00852A, 1SI-00852B, FO-03930, FO-03931, SW-02816, SW-02817, SW-02927A, SW-02927B, SW-02930A, SW-02930B, SW-04478, and SW-04479
T = 5.5 sec	1P-010A and 1P-010B
T = 10.5 sec	P-038A, P-038B, AF-04021 and AF-04023
T = 15.5 sec	P-032A and P-032C
T = 20.5 sec	P-032B and P-032D
T = 39.4 sec	1W-001C1
Motors Running Throughout Event	P-032E, P-032F, 1W-001B1, 1W-001A1, and 1W-001D1
Total Simulation Time	60 seconds

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Study Case: U2-TD-A

Time Sequence	Equipment
T = 0 sec	2P-015A, 2P-015B, 2CV-00112B, 2CV-00112C, 2CV-00313, 2RC-00427, 2SW-02907, 2SW-02908, 2SI-00852A, 2SI-00852B, FO-03930, FO-03931, SW-02816, SW-02817, SW-02927A, SW-02927B, SW-02930A, SW-02930B, SW-04478, and SW-04479
T = 5.5 sec	2P-010A and 2P-010B
T = 10.5 sec	P-038A, P-038B, AF-04020 and AF-04022
T = 20.5 sec	P-032B and P-032D
T = 25.75 sec	P-032E and P-032F
T = 39.4 sec	2W-001A1
Motors Running Throughout Event	P-032A, P-032C, 2W-001B1, 2W-001C1, and 2W-001D1
Total Simulation Time	60 seconds

Study Case: U2-TD-B

Time Sequence	Equipment
T = 0 sec	2P-015A, 2P-015B, 2CV-00112B, 2CV-00112C, 2CV-00313, 2RC-00427, 2SW-02907, 2SW-02908, 2SI-00852A, 2SI-00852B, FO-03930, FO-03931, SW-02816, SW-02817, SW-02927A, SW-02927B, SW-02930A, SW-02930B, SW-04478, and SW-04479
T = 5.5 sec	2P-010A and 2P-010B
T = 10.5 sec	P-038A, P-038B, AF-04020 and AF-04022
T = 20.5 sec	P-032B and P-032D
T = 25.75 sec	P-032E and P-032F
T = 39.4 sec	2W-001C1
Motors Running Throughout Event	P-032A, P-032C, 2W-001B1, 2W-001A1, and 2W-001D1
Total Simulation Time	60 seconds

Section III – Degraded Voltage Analysis

The motor starting analysis is performed in a plant configuration with a large break LOCA (Configuration L1-1X4 and Configuration L2-2X4) at the minimum 345 kV system voltage determined by Section III.2.08. This will place the 4.16 kV system voltage at a steady state voltage greater than the maximum degraded voltage relay's reset (pickup) setpoint. The motor starting analysis will be performed with study cases U1-TD-A and U1-TD-B for Unit 1; and study cases U2-TD-A and U2-TD-B for Unit 2. If, during a motor start, the voltage drops below the relay actuation setpoint, the minimum 345 kV system voltage may be adjusted, as necessary, to ensure the 4.16 kV system voltage recovers above the maximum pickup. Additionally, the 345 kV system voltage may be increased to ensure the containment accident fan does not drop out the degraded voltage relay because the 4.16 kV system voltage may not recover quickly enough to prevent separation due to the long acceleration time of the containment accident fan motor.

The minimum time delay relay setting when a safety injection signal is present is established in Section III.2.11. The purpose of this setting is to ensure the time delay is long enough to ride through the starting of safety related loads in a loss of coolant accident without prematurely separating from the preferred offsite power source. The acceptability of the minimum time delay is determined by reviewing the motor starting analysis performed above and determining the longest duration between the bus voltage dropping below the maximum degraded voltage relay actuation voltage ($V_{DO\ Max}$) and recovering above the maximum reset voltage ($V_{SS\ Max}$) on the 4.16 kV safety related bus. This will establish the minimum required time delay for the degraded voltage time delay relays with a loss of coolant accident (safety injection signal).

III.2.10 DETERMINATION OF OVERCURRENT TRIPPING TIMES FOR SAFETY RELATED CIRCUITS

The overcurrent tripping times of safety related circuits are determined to ensure that:

a. Under a degraded voltage condition, all safety related equipment is available and the protective device will not inadvertently trip on overcurrent, as long as there is sufficient voltage at the 345 kV system (all equipment are operating at equal to or greater than their minimum voltage requirements).
b. Under a degraded voltage condition with a safety injection signal (LOCA), the degraded voltage time delay will time out prior to a trip of any safety related equipment protective devices actuating on overcurrent due to motor starting (between the degraded voltage relay setpoint and the loss of voltage relay setpoint) when insufficient starting voltage exists and motors are stalled in a locked rotor current condition.
c. Under a degraded voltage condition during normal plant operation (without a safety injection signal), the degraded voltage time delay will time out prior to a trip of any safety related equipment protective devices due to higher running currents experienced as a result of reduced system voltage (between the degraded voltage relay setpoint and the loss of voltage relay setpoint).

The protective device overcurrent tripping times are utilized to establish the upper boundary of the time delay setpoints for the bus degraded voltage relays and bus time delay relays. This ensures that all safety related motors are available to be automatically loaded onto the emergency diesel generator after separation from the preferred offsite power supply. These tripping times also ensure the safety related loads are available throughout the normal operating voltage on the 345 kV system without tripping on overcurrent. The safety related static loads are not evaluated individually because they are constant impedance devices (as voltage decreases, current also decreases). However, they are included in the evaluations of the main feeder breakers at each bus. The protective device tripping times are established for each safety related bus and are determined as follows for each condition:

III.2.10.1 All safety related equipment is expected to operate without its protective device tripping on overcurrent when sufficient voltage exists at the terminals of the equipment for continuous operation (voltages equal to or greater that degraded voltage relay setpoints). This ensures that all safety related equipment is available and will operate at voltages equal to or greater than the safety limit (SL) 4.16 kV system voltage determined in Section III.2.04. The individual equipment and bus feeder breakers will be evaluated as follows to ensure no protective device overcurrent trips occur on overload due to a degraded voltage condition:

a. Gather all protective device characteristics for safety related equipment and bus feeder breakers including device setpoints and time current curves.

b. Gather all equipment technical data including nameplate voltage, nameplate current, for motors, locked rotor current, or KVA code, and load demand factor.

c. Evaluation of Motors: The evaluation of safety related motors ensures that at the minimum steady state voltage, the subsequent current increase will not trip the protective device on overcurrent. The motors are evaluated as follows: (1) The motor currents are calculated by ETAP when the 4.16 kV buses are operating at the safety limit voltage (See Section III.2.04); (2) The current at minimum voltage will be compared against the long time trip setpoint (power circuit breakers) or the rating (molded case circuit breakers and/or overload heater) of the protective device including device tolerances.

d. Evaluation of Bus Feeder Breakers: The bus feeder breaker protective devices cannot trip at the minimum voltage established based on the methodology in Section III.2.04 and is the minimum 4.16 kV system voltage (safety limit) utilized in setting the degraded voltage relays. Therefore, the bus feeder breaker protective devices long time trip setpoints or ratings (including tolerances) will be compared against the load currents evaluated in Section III.2.04, in which ETAP is utilized.

III.2.10.2 The degraded voltage time delay relay setpoints (with a safety injection signal) are established to ensure that no safety related equipment will trip the protective device on overcurrent during a loss of coolant accident prior to separating from offsite power. The equipment overcurrent tripping time of safety related equipment is determined to provide an input into the setting of the degraded voltage time delay relay setpoint. The overcurrent tripping time is established as follows when the 4.16 kV system voltage is below the degraded voltage relay setpoint and above the loss of voltage relay setpoint.

a. Gather all protective device characteristics for safety related equipment and bus feeder breakers including device setpoints and time current curves.

b. Gather all equipment technical data including nameplate voltage, nameplate current, and for motors, locked rotor current, or KVA code, and load demand factor.

c. Evaluation of 480V Motors (including Motor Operated Valves - MOVs): The safety related motors protective device tripping times are determined at locked rotor current because the voltage may be below the minimum starting voltage of the motors. The motors may be unable to come up to full speed due to insufficient bus voltage and would be at locked rotor current until either the protective device trips or voltage recovers. Therefore, the overcurrent tripping times will be established based on the safety related motors being at locked rotor for the full time duration. The motors are evaluated as follows: (1) During starting, the motors are constant impedance devices and the current is directly proportional to the voltage similar to a static device. In this calculation, the locked rotor current will be equal to the locked rotor current drawn when starting a motor at 90% of full voltage. The locked rotor current is determined at 90% of full voltage because all safety related motors are capable of starting at voltages as low as 90% of rated voltage (References VII.2.07 and VII.2.08). (2) The calculated locked rotor current will be compared to the time current curve of its supply breaker and a tripping time will be established.

(Eq. 11) $I_{max} = 0.9 * I_{ST}$

Where:

Imax = motor maximum locked rotor current at the minimum voltage

I_{ST} = Motor rated locked rotor current at nameplate voltage

d. Evaluation of 4.16 kV Motors: The 4.16 kV motors are evaluated using the same basic method as the 480 V motors. The motors are evaluated as follows: (1) For 4.16 kV motors, the locked rotor current will be equal to the locked rotor current drawn when starting a motor at 85% of full voltage. The locked rotor current is determined at 85% of full voltage because the only motors on the 4.16 kV safety related buses are the safety injection and auxiliary feedwater pump motors, which are capable of starting at voltages as low as 85% of rated voltage (References VII.4.39, VII.4.46, and VII.4.47). (2) The calculated locked rotor current will be compared to the time current curve of its supply breaker and a tripping time will be established.

(Eq. 11a) $I_{max} = 0.85 * I_{ST}$

e. Evaluation of safety related 480V MCC Source Breakers: The loads on the safety related MCCs are capable of starting when the voltage at the equipment terminals is equal to or greater than 90% of the nameplate voltage. During a degraded voltage condition the voltage on the 480V MCCs will be depressed due to the 4.16 kV system voltage being somewhere between the degraded voltage relay setpoint and the loss of voltage relay setpoint. Therefore the voltage on the MCC may be below the starting and running voltage requirements of the motors. The MCC source (and/or main, if exists) breaker is evaluated as follows:

   i. Induction motors are capable of starting and running at voltage greater than or equal to 90% of rated nameplate voltage (Reference VII.2.07 and VII.2.08). It is expected that all motors will start unless a single failure occurs. All induction motors modeled as "ON" at the MCC are considered to be starting for the evaluation of the load on the MCC. Induction motors are constant impedance loads when starting; therefore the locked rotor current will be directly proportional to the voltage. The locked rotor current is determined at 90% of rated voltage because all safety related motors are capable of starting at voltages as low as 90% of rated voltage. Therefore, the current drawn by induction motors during degraded voltage conditions will be determined at a voltage of 90% of motor rated voltage by multiplying the rated locked rotor current by 0.9. This will provide a conservative locked rotor current for each induction motor.

ii. Battery chargers are modeled as constant kVA devices. For this evaluation, the demand current (the product of demand factor and rated current) is corrected to its 75% of rated voltage value by dividing the demand current by 0.75.

iii. The Variable Frequency Drives (VFDs) feeding the charging pumps are modeled as constant kVA devices. For this evaluation the demand current is corrected to its 75% of rated voltage value by dividing the demand current by 0.75.

iv. The current drawn by the static loads supplied by the MCCs will be equal to the nameplate current of the equipment. This will provide a conservative full load current because static loads are constant impedance devices where current is directly proportional to voltage.

v. The total current drawn by the MCCs will be a summation of all the individual currents determined in Steps III.2.10.2.e.i through III.2.10.2.e.iv. The total current will then be compared against the source breaker's time current curve and the worst-case overcurrent trip time will be established. The total current calculated will provide the worst-case MCC current drawn during a degraded voltage condition.

f. Evaluation of safety related 480V Switchgear Breakers: The 480V switchgear breakers are evaluated for the first 8.6 seconds (Acceptance Criteria III.3.10) after the receipt of a safety injection signal (loss of coolant accident). This evaluation ensures that none of the switchgear breakers will trip as a result of increased current during degraded voltage conditions. This in turn ensures that the loads they feed are available as expected when the emergency diesel generator is ready to load within 14 seconds of a safety injection signal if there is insufficient voltage to supply the safety related loads (An imposed condition in Reference VII.1.11). The loading on the safeguards buses is determined by: (1) the safeguards motors that receive start signals within the first 8.6 seconds, i.e. the safety injection pump motor (1/2P-015A/B) and residual heat removal pump motor (1/2P-010A/B) (Reference VII.1.01). (2) The safeguards motors (sequenced after 8.6 seconds) that may be running prior to the event will be considered running. This includes service water motors (P-032A/B/C/D/E/F) and the containment accident fans (1/2W-001A1/B1/1C/D1). The auxiliary feedwater pumps (P-038A/B) and containment spray pump motor (1/2P-014A/B) will not be started within 8.6 seconds because they are sequenced on after 10 seconds (Acceptance Criteria III.3.10). (3) The remaining loads on the safeguards switchgear will be based on Calculation 2008-0025 (Reference VII.1.01). The 480V switchgear breakers need to be evaluated in 2 different voltage segments (Segment 1 = 90% > X ≥ 75%; and Segment 2 = X < 75%) to ensure the degraded voltage time delay relay setpoint prevents a spurious overcurrent protective device trip. For Segment 1, the safety related motors that receive a start signal from the safety injection signal have stalled because there is not sufficient starting voltage. However, the motors that are already operating prior to the safety injection signal will be operating at increased current but will not stall because motors are capable of operating at equal to or greater than 75% of rated voltage for up to 60 seconds with no damage (Reference VII.2.08). For Segment 2, all the running and started motors are operating at less than 75% rated voltage which is below the minimum running and starting voltage of the motors connected to the buses, therefore all motors will be in a stalled condition during this degraded voltage condition. Evaluation of Segment 1 and 2 will ensure that, during the start of safety related motors, the voltage dip on the 480V buses does not initiate the loss of voltage relays on the 4.16 kV switchgear. Therefore, the 480V switchgear is evaluated to ensure they to do not trip during all postulated degraded voltage conditions.

i. Segment 1 – The maximum current flow through the 480V switchgear main breaker is determined by a summation of the locked rotor currents at 90% rated voltage for the motors that start during the event, the running currents at 75% rated voltage for the equipment that would continue to run during the event, and the MCC current calculated in Item d. Conservatively, the locked rotor current will be determined at 90% rated voltage for the full voltage range of Segment 1. This will provide the maximum locked rotor current by the stalled motors for this range in voltage because the locked rotor current is directly proportional with terminal voltage. The running motors will conservatively be determined at 75% rated voltage. This provides the maximum current from the running motors because current is inversely proportional to the terminal voltage of the motor. The total current will be compared against the time current curve of the main feeder breaker for the switchgear.

(Eq. 12) $I_{T1} = \sum^{n}(0.9 * I_{ST(n)}) + \sum^{m}(MF * I_{R(m)} * DF_{R(m)}) + I_{MCC}$

Where:

I_{T1} = total switchgear current for segment 1
$I_{ST(n)}$ = locked rotor current for each motor starting during the event
n = number of motors that start
$I_{R(m)}$ = nameplate current for each motor that is running during the event
$DF_{R(m)}$ = demand factor for each motor that is running during the event and is determined within Reference VII.1.01
m = number of motors that are running
I_{MCC} = total current of MCC connected to switchgear
MF = 1.44; current multiplying factor at 75% voltage (Reference VII.2.09)

ii. Segment 2 – The maximum current flow through the 480V switchgear main breaker is determined by summing the locked rotor currents at 75% voltage for all motors that start and run (potentially stalled) during the event and the MCC current calculated in Item III.2.10.2.e.v. Conservatively the locked rotor current will be determined at 75% voltage for the full voltage range of Segment 2. This will provide the maximum locked rotor current by the stalled motors for this voltage range, because the locked rotor current is directly proportional to terminal voltage. The total current will be compared against the time current curve of the main feeder breaker for the switchgear.

(Eq. 13) $I_{T2} = \sum^{n} 0.75 * I_{Motor(n)} + I_{MCC}$

Where:

I_{T2} = total switchgear current for Segment 2
$I_{Motor(n)}$ = locked rotor current for each motor starting and running (potentially stalled) during the event
n = number of motors running and starting
I_{MCC} = total current of MCC connected to switchgear

iii. The total current calculated for Segment 1 and Segment 2 will then be compared against the main breaker's time current curve and the worst-case overcurrent trip time will be established. The total current calculated will provide the worst-case switchgear current during a degraded voltage condition coincident with a safety injection signal.

g. 4160 – 480V station service transformer breakers: The station service transformers (1X-13, 1X-14, 2X-13, and 2X-14) that feed the safety related 480V switchgear are protected on both the primary and secondary side of the transformer. As shown in Calculation 2001-0049 (Reference VII.1.02) the primary and secondary protective devices fully coordinate with each other. Therefore, the overcurrent trip time of the primary protective device on the 4.16KV switchgear will be at least equal to or greater than the trip time established for the secondary side main protective device on 480V switchgear. Therefore, the secondary side main protective device (480V switchgear main breaker) will be used to establish the limiting time delay for both protective devices.

h. The maximum allowable time delay during a safety injection is determined to be the most limiting trip time from the main breaker or individual protective devices for the equipment. This will establish the safety limit for the degraded voltage relay's time delay setpoint with a safety injection signal.

III.2.10.3 The degraded voltage time delay relay setpoints (without a safety injection signal) are established to ensure that no safety related equipment would trip its protective device on overcurrent during normal plant operation prior to separating from offsite power during a degraded voltage condition. The equipment overcurrent tripping time of safety related equipment is determined to provide an input into the setting of the degraded voltage time delay relay setpoint. The overcurrent tripping time is established when the 4.16 kV system voltage is below the degraded voltage relay setpoint and above the loss of voltage relay setpoint.

a. Gather all the protective device characteristics for safety related equipment and bus feeder breakers including device setpoints and time current curves.

b. Gather all the equipment technical data including nameplate voltage, nameplate current, and additional information for motors including locked rotor current or KVA code, and load demand factor.

c. Evaluation of 480V and 4.16 kV Motors: The safety related motors protective device tripping times are determined at a minimum running voltage 75% of nominal nameplate voltage. Induction motors are capable of operation at 75% of rated voltage at the motor terminals for up to 60 seconds without damage (Reference VII.2.08). It is expected that during the degraded voltage condition no equipment will be started because the PBNP control room will receive notification from ATC and will enter Technical Specification 3.8.1.C per operation procedure OP 2A (Reference VII.6.06) to declare offsite power inoperable. Equipment operation will be limited to ensure the safe operation of the PBNP units.

d. The 345 kV system is evaluated to ensure that a single contingency will not affect the ability of the transmission system to supply power to PBNP (Reference VII.8.03) and ATC is required under a single contingency to maintain the PBNP switchyard voltage not less than 90% of nominal system voltage per the Interconnection Agreement for PBNP (Reference VII.4.05). Therefore, it is not credible that the 345 kV system voltage will have a sustained voltage less than 90% of nominal voltage. If the voltage drops below 90%, the voltage on the 345 kV system is collapsing and will drop below the loss of voltage relays quickly and will separate the safeguards buses from offsite power. This should maintain the voltage at the terminal of the motor greater than or equal to 75% of rated voltage during normal plant operation.

e. The maximum running current for each individual motor will be calculated at a terminal voltage of 75% because this will provide the maximum worst-case current. In theory, current is inversely proportional to voltage for constant kVA loads. In actual practice, the relationship is non-linear (Reference VII.2.09). Based on interpolation of the data in table II in reference VII.2.09, the maximum current will be conservatively calculated by multiplying the nameplate current by 1.44 (Reference VII.2.09) and the maximum demand factor for the individual load. The following equation is utilized:

(Eq. 14) $I_{max} = 1.44 * I_R * DF_R$

Where:

I_{max} = motor maximum current at the minimum voltage

I_R = nameplate current for the motor

DF_R = demand factor for each motor that is running and is determined within Reference VII.1.01

f. Evaluation of 480 V safety related MCC Source (and/or main) Breakers: The total current on the safety related MCCs is the summation of the total running load during normal plant operation at degraded voltage condition. The total current is calculated as follows:

i. The motor currents will be calculated using the methodology described in Step e above and Equation 14.

ii. The current to static loads supplied by the MCC will be equal to the product of rated current and demand factor for each load (note that demand factor is set to 1.0 for static loads). This will provide a conservative full load current because static loads are constant impedance devices and the full load current is directly proportional to voltage.

iii. Battery chargers are modeled as constant kVA devices. For this evaluation, the demand current (the product of demand factor and rated current) is corrected to its 75% of rated voltage value by dividing the demand current by 0.75.

iv. The VFDs feeding the charging pumps are modeled as constant kVA devices. For this evaluation the demand current is corrected to its 75% of rated voltage value by dividing the demand current by 0.75.

v. The total MCC current will be a summation of all the individual currents determined in Steps (i) through (iv). The total current will then be compared against the feeder breaker's time current curve and the worst-case overcurrent trip time will be established. The total current calculated will provide the worst-case MCC current during a degraded voltage condition.

g. Evaluation of 480 V Switchgear Breakers: The total current on the safety related switchgear is the summation of the total running load during normal plant operation at degraded voltage condition. The total current is calculated as follows:

i. The motor currents will be calculated using the methodology described in Step c and Equation 14.

ii. The current to static loads supplied by the switchgear will be equal to the product of rated current and demand factor for each load (note that demand factor is set to 1.0 for static loads). This will provide a conservative full load current because static loads are constant impedance devices and the full load current is directly proportional to voltage.

iii. The total safety related MCC current is calculated from the methodology in step f above.

iv. The total non-safety related MCC current is conservatively determined by multiplying the breaker long time pickup setting by 1.25. A load equal to the maximum long time pickup current of the breaker provides the maximum potential current on the non-safety related breaker to be supplied from the switchgear without tripping the breaker. Therefore, this provides the maximum current from the non-safety related MCCs.

v. The pressurizer heater power panels are static load devices and the total current will be entered based on nameplate current. This will provide a conservative full load current because static loads are constant impedance devices and the load current is directly proportional to voltage.

vi. The total switchgear current will be a summation of all the individual currents determined in Steps i, ii, iii, iv, and v. The total current will then be compared against the main breaker's time current curve and the worst-case overcurrent trip time will be established. The total current calculated will provide the worst-case switchgear current during a degraded voltage condition.

h. 4160 - 480V station service transformer breakers: The station service transformers (1X-13, 1X-14, 2X-13, and 2X-14) that feed the safety related 480V switchgear are protected on both the primary and secondary side of the transformer. As shown in Calculation 2001-0049 (Reference VII.1.02) the primary and secondary protective devices fully coordinate with each other. The overcurrent trip time of the primary protective device on the 4.16 kV switchgear will be at a minimum equal to or greater than the trip time established for secondary main protective device on 480V switchgear. Therefore, the secondary protective device (480V switchgear main breaker) will be used to establish the limiting time delay for both protective devices.

i. The maximum allowable time delay during normal plant operation without a safety injection is determined to be the most limiting (shortest) trip time from a main breaker or individual protective device for the equipment. This will establish the safety limit for the degraded voltage relays time delay setpoint without a safety injection signal.

III.2.11 DETERMINE DEGRADED VOLTAGE RELAYS TIME DELAY SETPOINTS

The degraded voltage time delay relays perform two design functions to initiate a degraded voltage trip to disconnect the 4.16 kV safeguards buses from offsite power following either (1) a time delay associated with a safety injection signal or (2) a time delay without a safety injection signal (See Figure 1 in Section III.2.07). The first time delay setpoint (with a safety injection signal) is established to ensure quick grid separation for a sustained degraded voltage signal during a loss of coolant accident. This delay must be long enough to ride through the starting of accident loads without separating if the preferred offsite power voltage is acceptable. The second time delay setpoint is established to ensure that operating safety related equipment is not damaged or does not become unavailable due to protective device actuation under a sustained degraded voltage condition during normal plant operations (no safety injection signal present). Therefore, the two degraded voltage relay time delay setpoints are established for the safety related buses to ensure no spurious (unnecessary) trips of protective devices and/or no thermal damage occurs to safety related components.

The degraded voltage time delay relays provide the means to power the safety related buses with emergency power (via Emergency Diesel Generators) when offsite power is inadequate (i.e. degraded voltage or loss of voltage) to allow safe unit shutdown. Therefore, the degraded voltage time delay relays are provided in two-out-of-three logic to actuate after a specified time frame when a sustained degraded voltage condition is detected for each 4.16 kV safety related bus (References VII.5.02, VII.5.04, and VII.5.07). The degraded voltage time delay relays ensure that the Engineering Safety Features (ESF) equipment is protected from damage during the time frame that the degraded voltage relays have sensed a sustained degraded voltage until the relays actuate. The degraded voltage time delay relays are categorized as Category A instrument setpoints per Design Guide DG-I01 (Reference VII.4.03) and will utilize a criteria which corresponds to a 95% probability at a 95% confidence level (95/95) after the degraded voltage relay dropout setting is reached. The Block F relay time delay is also considered for the Train B (A06) safeguards buses.

Figure 1, in Section III.2.07, is a block diagram of the components that makeup each 4.16 kV safety related bus degraded voltage protection loop on both units. There are two buses (A-train and B-train) per unit. There are three independent loops per bus that supply a two-out-of-three coincidence logic (twelve independent loops total). This section describes the time delay set points established by blocks C, D and E.

Figures 3 and 4 below illustrate the setpoint determination sequence (numbered circles) and the relationship between the Safety Limit (SL), Analytical Limit (AL), Nominal Trip Setpoint (NTSP), Allowable Value (AV) and the Actual Trip Setpoint (ATSP) for the degraded voltage time delay relays. Figure 3 applies to time delay with a safety injection signal and Figure 4 applies to time delay without a safety injection signal.

Figure 3: Degraded Voltage Time Delay with a Safety Injection Signal

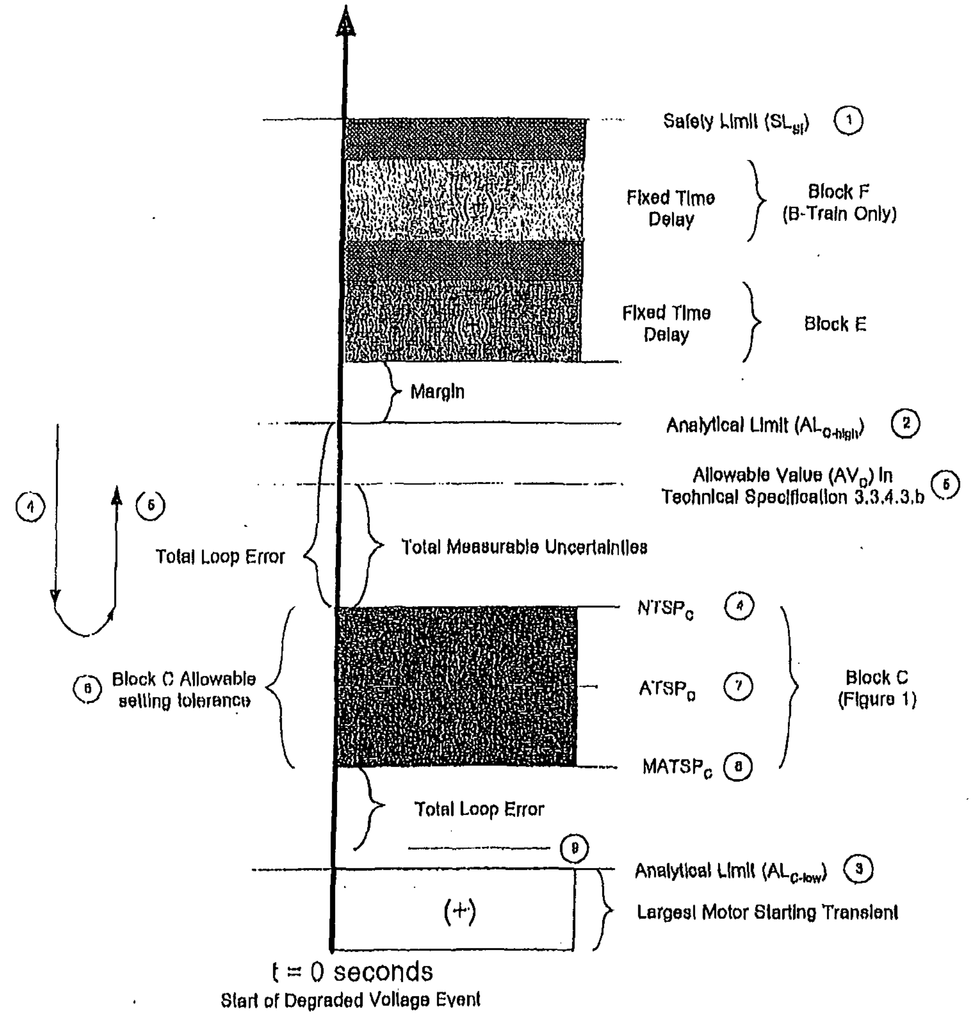
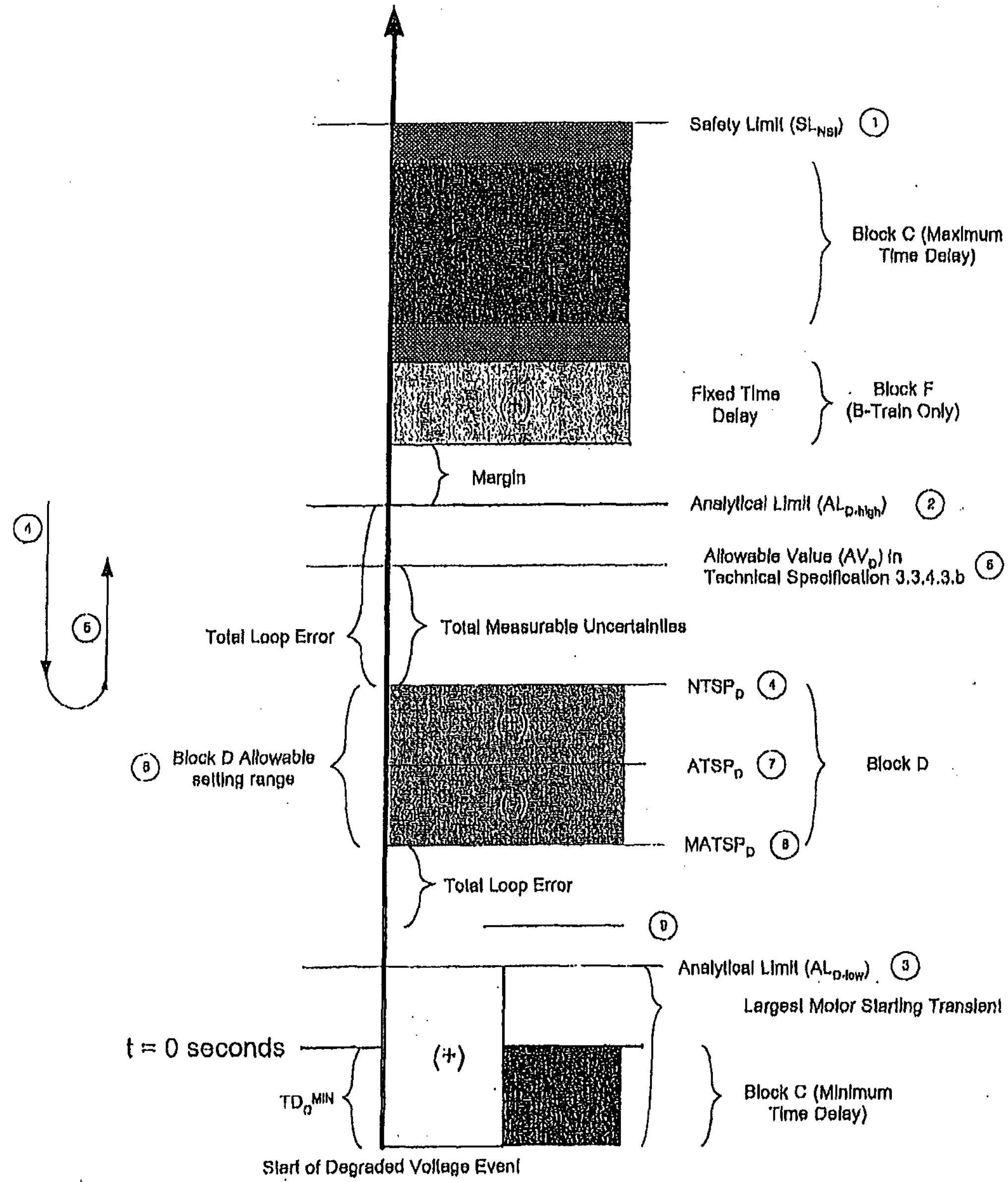


Figure 4: Degraded Voltage Time Delay without a Safety Injection Signal



The methodology of this Calculation is based on the guidance of Design Guide DG-I01 "Instrument Setpoint Methodology" (Reference VII.4.03). The sections below are an outline of the Calculation approach and determine the appropriate degraded voltage time delay relay setpoints.

III.2.11.1 The time delay loop error contributors for each relay are identified based the guidance within Design Guide DG-I01 (Reference VII.4.03). The following will determine whether each error contributor is applicable, random, nonrandom, independent, and/or a direction bias. The error contributors will be expressed in percent of relay setting (rather than in percent of relay setting span), to be consistent with the manufacturer's *published relay accuracy (see Reference VII.4.04):*

a. Block C and D Relay (See Figure 1 and Table 1)

i. Accuracy: Relay time delay setting accuracy (repeatability) in percent of setting is provided by both relay manufacturers. Because a time delay setting is approached from only one direction, linearity and hysteresis are not included in the accuracy term. Note that when drift is determined using as-left/as-found calibration data, relay accuracy is included as part of the calculated drift term, and does not need to be accounted for separately.

ii. Drift: Relay setpoint drift applies as a random uncertainty for both time delay settings. Drift can be calculated or given by the manufacturer. No manufacturer drift value is available, but relay calibrations performed since the mid-1990's (when the relays were installed) provide as-left / as-found data that can be used to calculate the drift using statistical methods described in Appendix H of DG-I01 (Reference VII.4.03). See item III.2.07.2 above for more explanation of this method of determining drift. |

iii. M&TE: The manufacturer of the M&TE provides an uncertainty associated with frequency of calibration of the M&TE. The uncertainty of the M&TE is random and independent in consideration of the relay time delay setpoint. However, when relay setting drift is determined using as-left/as-found calibration data, M&TE accuracy is included as part of the calculated drift term, and does not need to be accounted for separately (as long as the M&TE uncertainty is less than or equal to the M&TE used to perform the calibrations).

iv. Setting Tolerance: The setting tolerance establishes the allowable range to allow the technician to set the relay. Setting tolerance is expressed as a random (±) value around an ideal setting, although the tolerance can also be asymmetric (e.g., +2, -0). The tolerance range is established based on the device accuracy, MT&E accuracy used to calibrate the relays, the limitations of the technician in adjusting the device, and the need to minimize calibration and testing time.

v. Power Supply Effect: Relay time delay power supply affect is included in the total uncertainty provided by the manufacturer for both relays. The manufacturer provided a total uncertainty of the time delay relay to be utilized.

vi. Temperature Effect: Relay time delay power supply affect is included in the total uncertainty provided by the manufacturer for both relays. The manufacturer provided a total uncertainty of the time delay relay to be utilized.

vii. Humidity Effect: There is no uncertainty due to humidity changes provided by the relay manufacturer. The relays are rated over a temperature range of +10°C to +40°C (+50°F to +104°F) and have performed well under varying humidity conditions in the switchgear rooms for 10 years. Since no separate term for humidity effects is provided, these effects are taken to be negligible (essentially included in the overall accuracy for the relay) as described in DG-I01 (Reference VII.4.03). Therefore, no separate uncertainty due to humidity is considered in the total relay error.

viii. Radiation Effect: The relays are located in shielded plant areas (control building and diesel generator building) that will not experience radiation exposure greater than background, even under accident conditions. Therefore, no radiation effect is considered in the total relay error.

ix. Seismic or Vibration Effect: Seismic or Vibration Effect: There is no uncertainty due to seismic or vibration effect provided by the relay manufacturer. Per reference VII.4.04, the Model 27N (Block C) relay is a solid-state device rated at more than 6g ZPA biaxial broadband multi-frequency vibration without damage or malfunction, per ANSI C37.98-1978. The Model ETR (Block D) is a solid-state relay that is qualified for a standard response spectrum shape in IEEE Std. 501-1978. Therefore, no additional uncertainty is required for the relay for seismic conditions when maintained within capability.

b. Block E and F Relay (See Figure 1 and Table 1)

i. Accuracy: The block E (NBFD) relay and block F (RXMA-2) relay are fixed operating time relays. The manufacturer provides a maximum operating time of the relays that includes all uncertainty for the relays. The relays do not require calibration because no setpoint is required therefore drift and M&TE do not contribute additional uncertainty to the relay time delay.

III.2.11.2 As-found/as-left calibration data will be utilized to perform a statistical analysis to establish the drift error on the degraded voltage time delay relays for Block C and Block D. The general approach in performing a statistical analysis of the data is provided in Appendix H of Design Guide DG-I01 (Reference VII.4.03). The following is a summary of the steps performed in the statistical analysis:

a. As-left and as-found values for the degraded voltage relay dropout settings were compiled from historical plant relay calibration data collected between 1996 and 2004. The raw data for each of the twelve degraded voltage relays were tabulated in Attachment A, including as-left and as-found dropout values and as-left and as-found dates.

b. From the dropout values and dates, the number of days between calibrations and the measured drift over the interval was determined on the spreadsheet. To make the sample size representative of the nominal 18-month calibration interval, only those as-left/as-found pairings that were measured within ± 25% of 18 months (between 400 and 675 days apart) were analyzed.

c. From the population of as-left/as-found pairings that were suitable for analysis, the standard deviation was calculated using the Excel STDEV function.

d. The standard deviation was then multiplied by a factor based on the sample size to determine a 95% confidence level drift value.

e. DG-I01 provides the method of identifying and removing "outliers" from the sample population.

f. The data set was tested for "normalcy" by determining skewness and kurtosis using the procedure in DG-I01 Appendix H.

III.2.11.3 The total loop error (TLE) for each degraded voltage time delay relay is determined in accordance with Section III.2.07, Item III.2.07.3 and Equation 1. The total measurable uncertainty (TMU) for each degraded voltage time delay relay is determined in accordance with Section III.2.07, Item III.2.07.3 and Equation 2.

III.2.11.4 The degraded voltage time delay relays have two different schemes that account for the different plant operating conditions. The schemes are developed for a loss of coolant accident (safety injection signal) and for normal plant operations (without a safety injection signal). Figure 1 (Section III.2.07) shows a block diagram representation of the A-train and B-train degraded voltage sequence. Blocks C, D, and E (and F for B-train only) represent the time delay portion once the 4.16 kV bus voltage meets the dropout voltage setpoint. Note that Block C is a common time delay that contributes to both delays with and without a safety injection signal. Figures 3 and 4 show a pictorial representation of the process in which the degraded voltage time delay relays are established. The time delay with a safety injection signal will be established in Step III.2.11.5 and the time delay for normal plant operation (without a safety injection signal) will be established in Step III.2.11.6.

III.2.11.5 Refer to Figure 3 for the following discussion. The total degraded voltage time delay with a safety injection signal is established with Blocks C and E (and F for B-train only) from Figure 1 (Section III.2.07). The total time delay of the degraded voltage relays are a summation of Blocks C, E, and F relays actuation times. Blocks E and F are fixed operating time relays and therefore have a fixed time delay as shown in Figure 3. Block C provides an adjustable time delay established to ensure the operation of safety related equipment during a loss of coolant accident coincident with a degraded voltage condition. Therefore, the setpoint of the Block C time delay relay is determined to ensure the plant equipment is protected and no spurious overcurrent trips occur on safety related equipment during a loss of coolant event (safety injection signal) because the adjustable time delays for Blocks C and D are additive. This setpoint will also be used to establish the setpoint for the Block D relay during normal plant operation (without a safety injection signal). The following steps develop the Safety Limit (SL_{SI}), Analytical limits (AL_{high} and AL_{low}), Technical Specification Allowable Value (AV_C), and Block C relay setpoints ($NTSP_C$, $ATSP_C$, and $MATSP_C$) for the degraded voltage time delay scheme with a safety injection signal (see Figure 1).

a. The maximum allowable total combined time delay of the relays must ensure that during an accident coincident with degraded voltage, the time delay relays allow the safety related buses to separate from offsite power prior to spurious protection device trips due to overcurrent that would make safeguards equipment unavailable to sequence automatically onto the emergency diesel generators. The maximum allowable time delay is considered the safety limit (SL_{SI}) to protect all safety related equipment. The safety limit time delay is established based on the methodology in Section III.2.10 (See Figure 3, Item 1).

b. Two Analytical Limits (maximum and minimum) are required for the degraded voltage time delay with a safety injection signal ($AL_{C\text{-}high}$ and $AL_{C\text{-}low}$). The $AL_{C\text{-}high}$ is established to protect the SL_{SI} maximum allowable time delay by including the fixed operating time relays (Blocks E and F) and also including margin to permit a small change in the SL_{SI} without the requiring the Technical Specification Allowable Value to change. Block E and F fixed delays are included between the SL_{SI} and $AL_{C\text{-}high}$ to establish a Technical Specification Allowable Value to be directly compared to the as-found relay setpoint during calibrations to evaluate the operability of the relays to protect the Safety Limit. The $AL_{C\text{-}high}$ is determined by Equation 15 for A-train and B-train, which adds the fixed operate time delay (Blocks E and F). (See Figure 3, Item 2)

The AL_{C-low} is established to ensure that the time delay is long enough to ride through the starting of any one accident load without prematurely separating from the preferred offsite power source at the minimum allowable 345 kV system voltage. The AL_{C-low} is determined in Section III.2.05. (See Figure 3, Item 3).

$$\text{(Eq. 15)}\ AL_{C-high} = SL_{SI} - (TD_E + TD_F)$$

Where:

SL_{SI} = Maximum allow time delay, safety limit

TD_E = maximum operate time of Block E relay in seconds

TD_F = maximum operate time of Block F relay in seconds

c. The time delay nominal trip setpoint ($NTSP_C$) for Block C is determined to ensure that the Block C relay trip occurs before the analytical limit (AL_{C-high}) is reached. The difference between the $NTSP_C$ and AL_{C-high} accounts for all the uncertainties associated with the Block C relay for worst-case conditions (i.e. the Total Loop Error (TLE) for the Block C relay time delay). The $NTSP_C$ is calculated based on the guidance within Design Guide DG-I01 (Reference VII.4.03) as follows (See Figure 3, Item 4):

$$\text{(Eq. 16)}\ NTSP_C = \frac{AL_{C-high}}{1 + TLE^+}$$

Where:

$NTSP_C$ = Block C time delay nominal trip setpoint

d. TLE^+ = max time delay total loop error (%)The Technical Specification Allowable Value (AV_C) is determined to ensure sufficient margin exists between the Block C time delay relay nominal trip setpoint ($NTSP_C$) and the Analytical Limit (AL_{C-high}) to account for instrument uncertainties that are either not present or are not measured during periodic testing. This establishes Technical Specification SR 3.3.4.3.b (Reference VII.8.01) maximum time delay with a safety injection signal present. The AV_C is calculated based on the guidance within design guide DG-I01 (Reference VII.4.03) as follows (See Figure 3, Item 5):

$$\text{(Eq. 17)}\ AV_C = NTSP_C + TMU * NTSP_C$$

Where:

AV_C = Technical Specification Allowable value for Block C time delay

TMU = Total Measurable error – total instrument error for calibration conditions of these uncertainties that can be measured during performance of the surveillance

e. Note: The Allowable Value (AV_C) also provides the maximum as-found setting for the Block C relay based on TMU. This as-found limit ensures that the Block C Safety Limit (SL_{SI}) is protected and that the relay is exhibiting a 95/95 level of response.The setting tolerance for the Block C time delay relay is established is to allow an acceptable setpoint range for technicians to sufficiently set the relays. The setting tolerance will be determined to be equal to or greater than the timing accuracy of the degraded voltage relays (Block C) and the M&TE accuracy. This will ensure that the setting tolerance is large enough to allow the trip setpoints to be easily adjusted between the limits. The following equation establishes the setting tolerance (See Figure 3, Item 6):

$$\text{(Eq. 18)}\ ST_C = \pm\sqrt{a^2 + m^2} * NTSP_C$$

Where:

ST_C:	Block C allowable setting tolerance in seconds
a:	accuracy of the Block C relay time delay (%)
m:	M&TE error that are used to calibrate the relays (%)
$NTSP_C$:	nominal trip setpoint for Block C relay in seconds

f. The time delay actual trip setpoint ($ATSP_C$) and minimum actual trip setpoint ($MATSP_C$) are determined to provide a positive and negative range for calibration of the relays by the technicians ($MATSP_C$ to $NTSP_C$). The $ATSP_C$ is determined by subtracting ST_C^+ from the $NTSP_C$ (See Figure 3, Item 7). The $MATSP_C$ is determined by subtracting ST_C^- from the $ATSP_C$ (See Figure 3, Item 8).

g. The minimum time delay of the Block C relay is then calculated to be compared to the lower analytical limit ($AL_{C\text{-}low}$) to ensure that the time delay relay does not actuate prematurely during starting of any one accident load when the preferred offsite power voltage is acceptable. The minimum time delay is calculated with the following equation (See Figure 3, Item 9):

$$\text{(Eq. 19)}\ TD_C^{min} = MATSP_C - TLE^- * MATSP_C$$

Where:

TLE^-: min time delay relay total loop error (%)

TD_C^{min}: minimum actuation time of the Block C relay

h. The Minimum As-found Value (MAF_C) is determined to ensure sufficient margin exists between the Block C time delay minimum actual trip setpoint ($MATSP_C$) and the Analytical Limit (AL_{C-LOW}) to account for instrument uncertainties that are not measured during periodic testing. This as-found limit ensures that the Block C Analytical Limit (AL_{C-low}) is protected and that the relay is exhibiting a 95/95 level of response. The MAF_C is calculated based on the guidance within design guide DG-I01 (Reference VII.4.03) as follows:

(Eq. 19a) $MAF_C = MATSP_C - TMU_C * MATSP_C$

Where:

MAF_C = Minimum As-Found value for Block C time delay.

TMU_C = Total Measurable error – total instrument error for calibration conditions of those uncertainties that can be measured during performance of the surveillance. The TMU is applied to the as-left tolerance limit of interest ($MATSP_C$) consistent with other parts of this calculation, in which the error/uncertainty is based on a percent of the as-left calibrated value.

III.2.11.6 Refer to Figure 4 for the following discussion. The total degraded voltage time delay during normal plant operation (without a safety injection signal) is established with Blocks C and D (and F for B-train only) from Figure 1 (Section III.2.07). The Block C time delay was determined in Step III.2.11.5. The minimum and maximum time delay for the Block C relay contributes to the total time delay during normal plant operation. The total time delay of the degraded voltage relays are a summation of Blocks C, D, and F relays actuation times. Block F is a fixed time relay (for B-train only) and therefore has a fixed time delay as shown in Figure 4. For the development of the degraded voltage time delay during normal plant operation, Block C relay contributes two-fixed time delays based on the maximum actuation time (AL_{C-High} from Figure 3) and the minimum actuation time (TD_C^{min} from Figure 4) in establishing the setpoint for the Block D relay.

a. The Block D relay is established to ensure the operation of safety related equipment during normal plant operation (without a safety injection signal) with a degraded voltage condition. Therefore, the setpoint of the Block D time delay relay is determined to ensure safety related equipment will not be damaged or become unavailable due to a protective device actuation on overcurrent. The following steps develop the Safety Limit (SL_{NSI}), Analytical limits (AL_{D-high} and AL_{D-low}), Technical Specification Allowable Value (AV_D), and Block D relay setpoints ($NTSP_D$, $ATSP_D$, and $MATSP_D$) for the degraded voltage time delay scheme for normal plant operation (without a safety injection signal) in setting the Block D relay (Figure 1).

Note t = 0 seconds in Figure 4 represents the time at which Block D relay receives signal to begin timing.

b. The maximum allowable time delay of the relays is established to ensure that during normal plant operation, the time delay relay separates the safety related bus from offsite power prior to damage to equipment or spurious protection device trips due to overcurrent that would make equipment unavailable to automatically load onto the emergency diesel generators. The maximum allowable time delay is considered the safety limit (SL_{NSI}) to protect all safety related equipment. The safety limit is established in Section III.2.10. (See Figure 4, Item 1).

c. The degraded voltage time delay relays have a maximum and minimum Analytical Limit ($AL_{D\text{-}high}$ and $AL_{D\text{-}low}$) for normal plant operation. The $AL_{D\text{-}high}$ is established to protect the SL_{NSI} maximum allowable time delay by including definite time delay relay (Block F), Block C maximum time delay ($AL_{C\text{-}High}$) and include margin to permit a small change in the SL_{NSI} without requiring a change to the Technical Specification Allowable Value. Block C and F (B-train only) are included between the SL_{NSI} and $AL_{D\text{-}high}$ to establish a Technical Specification Allowable value to be directly compared to the as-found relay setpoint during calibrations to evaluate operability of the relays. The $AL_{D\text{-}high}$ is determined in Equation 20 for A-train and B-train, which adds the specified time delay relays and margin. (See Figure 4, Item 2).

The $AL_{D\text{-}low}$ is established to ensure that the time delay is long enough to ride through the largest motor starting voltage transient during normal plant operation without separating the bus from the preferred offsite power source. Typically, this transient is the start of a reactor coolant pump when recovering from an outage. $AL_{D\text{-}low}$ is determined in Equation 21 for A-train and B-train. (See Figure 4, Item 3).

$$\text{(Eq. 20)}\quad AL_{D-high} = SL_{NSI} - \left(AL_{C-high} + TD_F\right)$$

Where:

SL = Maximum allow time delay, safety limit

$AL_{C\text{-}high}$ = maximum time delay of Block C relay in seconds, which is the analytical limit

TD_F = maximum operate time of Block F relay in seconds (B-Train only)

$$\text{(Eq. 21)}\quad AL_{D-low} = M_{ST} - TD_C^{Min}$$

Where:

M_{ST} = largest motor starting transient in seconds

TD_C^{Min} =minimum actuation time of the Block C relay (see Step g)

d. Note: The t = 0 in Figure 4 establishes the time at which the Block D time delay begins, which is after the completion of the Block C relay as shown in Figure 1. The time delay nominal trip setpoint ($NTSP_D$) for Block D is determined to ensure that the Block D relay trip occurs before the analytical limit ($AL_{D\text{-}high}$) is reached. The difference between the $NTSP_D$ and $AL_{D\text{-}high}$ accounts for all the uncertainties associated with the Block D relay for worst-case conditions. The $NTSP_D$ is calculated based on the guidance within Design Guide DG-I01 (Reference VII.4.03) as follows (See Figure 3, Item 4):

$$\text{(Eq. 22)}\quad NTSP_D = \frac{AL_{D-high}}{1 + TLE^{+}}$$

Where:

$NTSP_D$ = Block D time delay nominal trip setpoint

TLE^{+} = max time delay relay total loop error (%)

e. The Technical Specification Allowable Value (AV_D) is determined to ensure sufficient margin exists between the Block D time delay relay nominal trip setpoint ($NTSP_D$) and the Analytical Limit ($AL_{D\text{-}high}$) to account for instrument uncertainties that are either not present or are not measured during periodic testing. This establishes Technical Specification SR 3.3.4.3.b (Reference VII.8.01) maximum time delay without a safety injection signal present. The AV_D is calculated based on the guidance within Design Guide DG-I01 (Reference VII.4.03) as follows (See Figure 4, Item 5):

$$\text{(Eq. 23)}\quad AV_D = NTSP_D + TMU * NTSP_D$$

Where:

AV_D = Technical Specification Allowable value for Block D time delay

TMU = Total Measurable error – total instrument error for calibration conditions of these uncertainties that can be measured during performance of the surveillance

Note: The Allowable Value (AV_D) also provides the maximum as-found setting for the Block D relay based on TMU. This as-found limit ensures that the Block D Safety Limit (SL_{NSI}) is protected and that the relay is exhibiting a 95/95 level of response.

f. The setting tolerance for the Block D time delay relay is established to allow an acceptable setpoint range for technicians to sufficiently set the relays. The setting tolerance will be determined to be equal to or greater than the timing accuracy of the Block D relays and the M&TE accuracy. This will ensure that the setting tolerance is large enough to allow the trip setpoints to be easily adjusted between the limits. The following equation establishes the setting tolerance (See Figure 4, Item 6):

$$\text{(Eq. 24)}\ ST_D = \pm\sqrt{a^2 + m^2} * NTSP_D$$

Where:

ST_D: Block D allowable setting tolerance (%)

a: accuracy of the Block D time delay relays (%)

g. m: M&TE error that are used to calibrate the relays (%)The time delay actual trip setpoint ($ATSP_D$) and minimum actual trip setpoint ($MATSP_D$) are determined to provide a positive and negative range for calibration of the relays by the technicians ($MATSP_D$ to $NTSP_D$). The $ATSP_D$ is determined by subtracting ST_C^+ from $NTSP_D$ (See Figure 4, Item 7). The $MATSP_D$ is determined by subtracting ST_D^- from $ATSP_D$ (See Figure 4, Item 8).

h. The minimum time delay of the Block D relay is then calculated to be compared to the lower analytical limit ($AL_{D\text{-}low}$) to ensure that the time delay relay does not actuate prematurely during starting of any load when the preferred offsite power voltage is acceptable. The minimum time delay is calculated with the following equation (see Figure 4, Item 9):

$$\text{(Eq. 25)}\ TD_D^{min} = MATSP_D - TLE^- * MATSP_D$$

Where:

TLE^-: min time delay relay total loop error (%)

TD_D^{min}: minimum actuation time of the Block D relay

i. The Minimum As-found Value (MAF_D) is determined to ensure sufficient margin exists between the Block D time delay minimum actual trip setpoint ($MATSP_D$) and the Analytical Limit (AL_{D-LOW}) to account for instrument uncertainties that are not measured during periodic testing. This as-found limit ensures that the Block D Analytical Limit (AL_{D-low}) is protected and that the relay is exhibiting a 95/95 level of response. The MAF_D is calculated based on the guidance within design guide DG-I01 (Reference VII.4.03) as follows:

(Eq. 25a) $MAF_D = MATSP_D - TMU_D * MATSP_D$

Where:

MAF_D = Minimum As-Found value for Block D time delay.

TMU_D = Total Measurable error – total instrument error for calibration conditions of those uncertainties that can be measured during performance of the surveillance. The TMU is applied to the as-left tolerance limit of interest ($MATSP_D$) consistent with other parts of this calculation, in which the error/uncertainty is based on a percent of the as-left calibrated value.

III.2.12 Determine Potential MOV Stall Time Windows

The voltage requirements for the safety related MOVs are evaluated in Calculation P-90-017 (Reference VII.1.25). Calculation P-90-017 uses Calculation P-89-031 (Reference VII.1.06) to determine that the MOVs will operate for MCC voltages of 420 V or higher. Therefore, it is possible that the MOVs will stall when the MCC voltage drops below 420 V.

There is a potential that the voltage at MCCs 1B-32, 1B-42, 2B-32, and 2B-42 may dip below 420 V during load sequencing (motor starts). The MOVs fed from these MCCs may stall during these dips. For MOVs that change position during load sequencing, the times and durations where the MCC voltage dips below 420 V during the sequencing will be determined to support the accident analysis.

The times at which the voltage is below 420 V will be determined by evaluating the ETAP voltage profiles for motor starting at the degraded voltage relay safety limits (Attachments G9 through G24). The potential stalling of MOVs may impact the required operation time for valves required to support the accident analysis. The evaluation of the additional time delay for MOVs is analyzed in Calculation 97-0041 (Reference VII.1.11). There are no acceptance criteria related to the potential MOV stall times within this calculation.

III.3 ACCEPTANCE CRITERIA

III.3.01 Acceptance criteria for minimum steady state load voltage: All safeguards motors shall be maintained above their minimum allowable continuous running voltage at the terminals of the motors (90% of rated voltage) and the voltage limits are provided in Calculation 2001-0033 and Calculation 2003-0007 (References VII.1.04 and VII.1.05). This ensures that the required safeguards motors are capable of performing their intended safety functions as required to meet PBNP GDC 39 (Reference VII.8.04).

III.3.02 Acceptance criteria for minimum steady state bus voltage: Safeguards motor control centers 1B-32, 2B-32, 1B-42 and 2B-42 shall have a steady state bus voltage maintained at greater than or equal to 420V. This is to ensure the safeguards motor operated valves have sufficient voltage to perform their intended safety function to meet PBNP GDC 39 (Reference VII.8.04). The motor operated valves minimum voltage is determined in Calculation P-89-031 (Reference VII.1.06).

III.3.03 Acceptance criteria for motor starting analysis: Motors that are required to start during a loss of coolant accident must be capable of starting at the minimum allowable steady state bus voltages. The starting safeguards motors shall be capable of starting at the minimum allowable steady state system voltage. The motors operating during the motor starting event shall maintain a minimum operating voltage greater than 75% of rated voltage for less than 60 seconds (Reference VII.2.08) and achieve greater than minimum steady state voltage after 60 seconds. This ensures that the required safeguards motors are capable of performing their intended safety functions as required to meet PBNP GDC 39 (Reference VII.8.04).

III.3.04 Acceptance criteria for motor starting analysis: The voltage at the 4.16 kV and 480 V safeguard buses shall be greater than 3276 V and 264 V, respectively (Reference VII.1.08). This ensures that the depressed voltage at the safeguards buses will not actuate the loss of voltage relays during safeguard motor starting when the minimum required 345 kV system voltage is available.

III.3.05 Acceptance criteria for motor starting analysis at the 4.16 kV bus minimum voltage (Safety Limit with offsite power): The motor acceleration time for the safety injection pump motors shall be less than 8.23 seconds (Reference VII.1.11), for the residual heat removal pumps shall be less than 1.2 seconds (Reference VII.1.11), for the containment spray pumps shall be less than 3.3 seconds (Reference VII.1.11), for the containment accident fans shall be less than 15.1 seconds (Reference VII.1.11) and for the service water pumps shall be less than 6.0 seconds (Reference VII.1.11) with offsite power available. These motor acceleration criteria ensure that the starting times meet the requirements of the FSAR Chapter 14 Accident Analysis.

III.3.06 Acceptance criteria for degraded voltage relay dropout and reset voltage setpoints: The degraded voltage relay dropout voltage setpoint shall provide a 95% probability at a 95% confidence level (95/95) to protect the minimum steady state voltage requirements of the 4.16 kV safeguard buses (safety limit). This ensures that the required safeguards motors are capable of performing their intended safety functions as require to meet PBNP GDC 39. (References VII.8.04 and VII.4.03).

III.3.07 Acceptance criteria for the minimum required 345 kV system voltage: The minimum steady state 345 kV system voltage shall be equal to or greater than the voltage required to maintain the safety related 4 kV buses above the maximum reset voltage for the degraded voltage relays. This ensures that the 4.16 kV system voltage will recover to a voltage greater than the reset voltage of the relays to reduce the probability of safeguards buses separating from the preferred offsite power source due to short-term undervoltage transients. This allows the safeguards motors to perform their intended safety functions as required to meet PBNP GDC 39. (Reference VII.8.04).

III.3.08 Acceptance criteria for safeguards equipment overcurrent protective devices: The safeguards equipment overcurrent protective devices, including the incoming source breakers to the safeguards buses, shall not trip at the minimum system voltage assuming that the voltage is present indefinitely. This ensures that the required safeguards motors are capable of performing their intended safety functions as require to meet PBNP GDC 39 (Reference VII.8.04).

III.3.09 Acceptance criteria for the degraded voltage time delay relays with a safety injection signal: The time delay relays setpoint shall ensure that no safeguards equipment trips on overcurrent prior to separating from offsite voltage. The time delay relay setpoint shall ensure that starting of accident loads will occur without separating from offsite power when voltage is acceptable. This ensures that the required safeguards motors are capable of performing their intended safety functions as required to meet PBNP GDC 39 (Reference VII.8.04) and will not unnecessarily challenge the Emergency Diesel Generators.

III.3.10 Acceptance criteria for the degraded voltage time delay relays with a safety injection signal: The maximum time delay shall be less than 8.6 seconds when a safety injection signal is present coincident with a degraded voltage signal. The allowable assumed time for the emergency diesel generator output breaker closure is 14 seconds (Reference VII.1.11) to meet the FSAR Chapter 14 Accident Analysis (References VII.8.05, VII.8.06, VII.8.07, VII.8.08, VII.8.09, and VII.8.10). A time delay of 4.427 seconds (3.375 second for the EDG breaker close delay relay + 0.886 second for the 4160 V loss of voltage relay time delay + 0.083 second for the auxiliary relays + 0.083 second for the EDG breaker closure) is subtracted to account for the loss of voltage protection scheme, accounting for relay maximum settings and total uncertainty of each component (Reference VII.1.08). An additional time delay of 0.9 seconds (rounding up from Input III.5.19) is subtracted to account for the residual voltage decay when the main source breaker of the 4.16 kV safeguards bus opens and the loss of voltage relay senses an undervoltage. This ensures that the required 14 seconds time delay (Reference VII.1.11) is not exceeded in order to meet the requirements of the Accident Analysis contained in the FSAR Chapter 14 (References VII.8.05, VII.8.06, VII.8.07, VII.8.08, VII.8.09, and VII.8.10).

III.3.11 Acceptance criteria for the degraded voltage time delay relays without a safety injection signal (normal plant operation): The time delay relays setpoint shall ensure that safeguards equipment is not damaged or will not become unavailable due to protective device actuation caused by sustained degraded voltage conditions during normal plant operation. The time delay relay setpoint shall ensure that starting of large 4.16kV system motors (e.g. reactor coolant pump motors) will occur without separating from offsite power when voltage is acceptable. Establishment of the loss of voltage relay voltage setpoints ensures that the large motor starts are maintained greater that 80% of nameplate to ensure the relays do not actuate (Reference VII.1.08). This ensures that the required safeguards motors will be capable of performing their intended safety functions as required to meet PBNP GDC 39 (Reference VII.8.04).

III.3.12 Acceptance criteria for minimum voltage requirements of battery chargers: the battery chargers shall be maintained above 412 V during steady state conditions (Assumption III.4.04). This ensures that the required battery chargers perform their intended safety functions as required to meet PBNP GDC 39 (Reference VII.8.04).

III.3.13 Acceptance criteria for minimum steady state bus voltage to support MCC minimum voltage requirements for their control circuits: The safeguards MCCs listed below shall have a steady state bus voltage maintained at or above the values tabulated below:

MCC	Voltage
1B-30	408V
1B-32	422V
1B-39	N/A
1B-40	418V
1B-42	426V
1B-49	N/A
2B-30	406V
2B-32	424V
2B-39	N/A
2B-40	417V
2B-42	422V
2B-49	N/A

There are no voltage requirements for the 1/2B-39 and 1/2B-49 MCCs for inrush conditions because the chargers they feed are energized prior to the event and, if stripped, will not be re-energized automatically. Similarly, the battery charger loads on 1B-32 (1B52-3212H) and 2B-42 (2B52-4212B) are energized prior to the event and, if stripped, will not be re-energized automatically. Therefore, the inrush voltage requirements for these circuits are not used as the bounding values for inrush voltage at MCCs 1B-32 and 2B-42. The circuit with the next most limiting voltage for inrush conditions is taken as the minimum required voltage at these MCCs. Note that the charger circuits in these MCCs must be considered for hold in, and they provide the limiting voltage for MCCs 1B-32 and 2B-42 in the next criteria.

This is to ensure that the control circuits for the 480V MCC safety related loads have sufficient voltage to perform their intended safety function (pick up when required) to meet PBNP GDC 39 (Reference VII.8.04). The minimum voltage requirements for these control circuits are determined in Calculation 2005-0008 (Reference VII.1.10).

III.3.14 Acceptance criteria for hold-in voltage to support MCC requirements for control circuits: Safeguards motor control centers 1B-30, 2B-30, 1B-40, 2B-40, 1B-32, 2B-32, 1B-42 and 2B-42 shall have a bus voltage maintained at greater than or equal to the following during motor starting:

MCC	Voltage
1B-30	279 V
1B-32	365 V
1B-39	365 V
1B-40	387 V
1B-42	288 V
1B-49	365 V
2B-30	279 V
2B-32	288 V
2B-39	365 V
2B-40	387 V
2B-42	365 V
2B-49	365 V

For MCCs 1B-32, 1B-39, 1B-49, 2B-39, 2B-42, and 2B-49 the minimum required voltage at the battery charger contactor for hold-in is 360 V per Calculation 2005-0008 (Reference VII.1.10). An additional 5 V is added to this value to give a conservative minimum voltage at the MCC. The 5 V accounts for the voltage drop between the MCC and contactor. This value is based on the bounding MCC-contactor combination, which occurs between MCC 1B-32 and the D-109 charger with the charger in current limit with a terminal voltage of 412 V. The charger draws 106 kVA (Reference VII.1.01), or 148.5 A in current limit at 412 V when conservatively treated as a constant power load. Using the cable length and impedance data from Reference VII.1.05, the cable impedance is 0.0195 Ω. Conservatively using the standard engineering formula $\Delta V = \sqrt{3}\ I|Z|$ gives a voltage drop of 5 V.

This is to ensure that the control circuits for the safety related 480V MCC loads have sufficient voltage to prevent dropping out during motor starts and to ensure that they are capable of performing their intended safety functions to meet PBNP GDC 39 (Reference VII.8.04). The safety related 480V MCC control circuits hold-in voltage requirements are calculated in Calculation 2005-0008 (Reference VII.1.10). The circuit with the next most limiting voltage for inrush conditions is taken as the minimum required voltage at these MCCs.

III.3.15 Acceptance criteria for the static motor starting analysis for the non-safegaurds 4kV motors 1(2)P-001A/B, 1(2)P-025A/B, and 1(2)P-028A/B: The terminal voltage at the non-safeguards 4 kV motors shall not drop below 80% of rated voltage during motor starting.

Reference VII.1.04 indicates the minimum acceptable terminal voltage for the RCP motors [1(2)P-001A/B] is 80% of rated voltage (3200 V) when starting. Reference VII.4.51 indicates the minimum acceptable terminal voltage for the new feedwater pump [1(2)P-028A/B] and condensate [1(2)P-025A/B] motors is also 80% of rated voltage (3200 V) when starting.

III.4 ASSUMPTIONS

Validated assumptions:

III.4.01 It is assumed that the uncertainty of the M&TE utilized to calibrate the dropout and pickup voltage setting of the degraded voltage relays will be +0.105% or less.

Basis: The M&TE currently required by calibration procedure is a Fluke 8505A or equivalent, which has an uncertainty of 0.105% when calibrated on a 12 month cycle (References VII.6.01, VII.6.02, VII.6.03, VII.6.04, VII.6.07, and VII.4.18). Therefore the M&TE uncertainty will be equal to or less than ±0.105% when performing the calibration of the dropout and pickup voltage setting of the degraded voltage relays. The calibrations utilize the 100V range, for which a maximum full scale reading is 160.000V, to measure an approximate 120V signal. This provides approximately an additional 0.005% error to account for the number of counts with a 1 mV resolution.

III.4.02 It is assumed that the uncertainty of the M&TE utilized to calibrate the time delay settings of the degraded voltage relays will be + 0.01% or less.

Basis: The M&TE currently required by calibration procedure is a Multi-Amp TV-2 or equivalent, which has an uncertainty of 1,000,000 Hz ± 25 Hz or ±0.0025% as an acceptance criteria to calibrate the M&TE (References VII.4.31)

III.4.03 It is assumed that the temperature range of the degraded voltage relay in the Vital Switchgear Room is 60 degrees Fahrenheit to 104 degrees Fahrenheit.

Basis: The design of the HVAC system is that with a worst-case outside air temperature of −15 degrees Fahrenheit, the ambient temperatures in the general areas of the turbine building are 65 degrees Fahrenheit (Reference VII.4.24). The maximum allowable temperature allowed during operator rounds for the Vital Switchgear Room is 85 degrees Fahrenheit and is established to maintain the D-05 and D-06 Battery Rooms to less then 90 degrees Fahrenheit for operability of the batteries (Reference VII.4.25). A review of operator logs of the Vital Switchgear room reveals that the temperature stays between 60 and 85 degrees Fahrenheit (See Attachment H6), therefore it is reasonable to assume an ambient temperature range of 60 to 85 degrees Fahrenheit for the Vital Switchgear Room. An additional 19 degrees Fahrenheit are conservatively added to the upper end of the range to account for the difference in temperature between inside the cubicle and the external ambient temperature. This is conservative because the only heat load in the cubicles is the heat from the bus bar and relays. Therefore, the temperature of the degraded voltage relays would range between 60 and 104 degrees Fahrenheit. This is conservative at the lower end of the range because the relays and bus bar generate heat and will bring the temperature inside the cubicles above 60 degrees. The 19 degrees added to the upper end of the range is conservative because the amount of heat added by the bus bars and relays is small, and given the volume and surface area of the enclosure, a rise of more than 10 degrees is unlikely.

III.4.04 It is assumed that the minimum steady state operating voltage of Battery Chargers D-07, D-08, D-09, D-107, D-108 and D-109 is 412 V.

Basis: The battery chargers provide power to the safety-related 125 V_{DC} system and maintain the station batteries at full charge. The fully charged station batteries are capable of providing power to the 125 V_{DC} system for at least one hour. The minimum voltage (-10% of 480 V) stated in the charger manuals ensures that 1% voltage regulation is maintained at the output of the charger over its full output current range. If the battery charger is supplied with a voltage outside the stated range, the voltage regulation may increase (i.e. regulation could be >1%), but the charger output will not fail. The battery charger would still be capable of providing sufficient voltage to the DC system to support the 125 V_{DC} system load and maintain the battery at full charge. The battery charger test report for the PCP chargers shows that at a minimum voltage of 412 V and the output voltage is maintained within DC system voltage requirements. The Westinghouse battery chargers are of similar design and are assumed operate in a similar manner. (References VII.4.27 and VII.4.28)

III.4.05 It is assumed that the temperature range of the degraded voltage relay in the Diesel Generator Building Switchgear rooms is 50 to 105 degrees Fahrenheit with an uncertainty of + 0.4% for the ABB 27N relay over this temperature range.

Basis: The basis for the temperature range of the switchgear rooms in the diesel generator buildings is developed in Engineering Evaluation EE 2005-0013 (Reference VII.1.09). The engineering evaluation accounts for the temperature inside the switchgear cubicle during minimum and maximum conditions. The vendor provides a uncertainty of ± 0.4% for a temperature range of 50 to 104 degrees Fahrenheit (10 to 40°C). However, Work Order 0510753 (Reference VII.4.30) performed a test on the ABB 27N by varying the relay ambient temperature between approximately 60 to 110 degrees Fahrenheit while maintaining control voltage constant. The relay test showed that over the range a maximum variation of 0.2% of setting. Therefore, the vendor provided uncertainty of ± 0.4% was used over the range of 50 to 105 degrees Fahrenheit. 1 degree Fahrenheit over the vendor stated range would have a negligible effect on the uncertainty based on the test performed under Work Order 0510753 (Reference VII.4.30)

III.4.06 It is assumed that the cable and fuse impedance will have a negligible effect on the burden and ratio correction factor of the potential transformer supplying the degraded voltage relays.

Basis: The highest burden on the potential transformer, when the relay is required to operate, is 5.2 VA (or approximately 0.043 amps at 120 V nominal voltage). The voltage drop across the cables would be negligible to the degraded voltage relays because the potential transformer and degraded voltage relay are located in either the same or adjacent switchgear cubicle with a relatively short cable length. Additionally, the voltage drop across the fuse would be negligible due to the maximum current of 0.043 Amps since the resistance would be significantly less than 1 ohm. Therefore, the cable and fuse impedance have a negligible affect on the ratio correction factor of the potential transformer.

III.4.07 It is assumed that the ABB 27N degraded voltage time delay repeatability is ±5% of setting.

Basis: The manufacturer's published 27N relay time delay repeatability is ± 10% of setting (Reference VII.4.04). The published ±10% value is based on the setting the relay's time dial using tap (dial) settings on the 27N front bezel. However, the time delay setting may be adjusted more a precisely using time delay potentiometer R41. The manufacturer does not provide the affects of repeatability on the accuracy of the 27N relay if calibrated using the R41 potentiometer. The manufacturer factory calibrates the relays prior to release with a maximum allowable variation from the dial setting of ±5% of tap setting.

Point Beach relay calibration practice is to set the 27N time delay precisely using the relay's R41 internal potentiometer, rather than by the dial settings. ABB has acknowledged that the potentiometer will provide tighter time delay repeatability than the dial settings.

Repeatability of the time delay setting is affected by temperature, control voltage, and inherent accuracy, similar to the 27N relay degraded voltage setting repeatability (Reference VII.4.04). To determine the 27N sensitivity to variations in ambient temperature and control voltage, Work Order 0510753 was performed to bench test a spare 27N relay (Reference VII.4.30). The test showed that the relay time delay setting varied approximately 0.3% of setting over the voltage range of 100 to 140 V_{DC}, and approximately 1.5% of setting over the temperature range of 60 to 110 degrees F. The temperature and voltage ranges during the test reasonably bound the conditions expected for the relay's installed location. The test data supports a 27N time delay total repeatability value that is smaller than the manufacturer's published value of ± 10%.

Therefore, a repeatability value of ± 5% (greater than 2 sigma) of setting is conservatively assumed when calibrated is performed with the internal potentiometer. This provides more than twice the uncertainty observed from combined temperature and control voltage effects during bench testing of a spare relay. The value is also consistent with the manufacturer's own release criterion.

Relay drift includes the relay inherent accuracy. Drift of the 27N time delay setting has been determined separately (see Section III.7.07) based on as-found/as-left calibration data, and will be combined statistically with the ± 5% repeatability to account for any unmeasurable time delay errors caused by relay temperature and control voltage variations.

III.7 RESULTS

III.7.01 Minimum 4.16 kV system voltage (Calculation Section III.6.03)

The minimum voltages (safety limits) for the safety related 4.16 kV buses are:

Switchgear	Minimum Voltage
1A-05	3923 V
1A-06	3923 V
2A-05	3912 V
2A-06	3927 V

The following is a summary of the voltage at the critical equipment for Unit 1 A-Train contained in Attachment G1:

Bus	Breaker	Equipment ID	Equipment Voltage in Volts
1A-05	1A52-59	1P-015A	3921
1A-05	1A52-65	P-038A	3921
1B-03	-	1B-03	428
1B-03	1B52-10A	1P-011A	426
1B-03	1B52-10C	P-032A	425
1B-03	1B52-11C	P-032B	424
1B-03	1B52-12A	1P-010A	425
1B-03	1B52-14A	1P-014A	426
1B-03	1B52-15A	1W-001A1	422
1B-03	1B52-15B	1W-001B1	422
1B-30	-	1B-30	420
1B-30	1B52-302D	P-206A	419
1B-32	-	1B-32	426
1B-32	1B52-329B	W-014A	418
1B-32	1B52-329H	W-012A	419
1B-32	1B52-3212H	D-109	424
1B-39	1B52-391	D-07	426

Note that the safety limit voltage for Unit 1 A-train is being driven by the overcurrent protective device trip current for the service water pumps.

Section III – Degraded Voltage Analysis

The following is a summary of the voltage at the critical equipment for Unit 1 B-Train contained in Attachment G2:

Bus	Breaker	Equipment ID	Equipment Voltage in Volts
1A-06	1A52-85	1P-015B	3911
1B-04	-	1B-04	431
1B-04	1B52-18A	1W-001C1	426
1B-04	1B52-18B	1W-001D1	423
1B-04	1B52-19A	1P-014B	429
1B-04	1B52-20C	P-032C	424
1B-04	1B52-21A	1P-010B	428
1B-04	1B52-23B	1P-011B	430
1B-40	-	1B-40	428
1B-40	1B52-401B	W-183B	426
1B-40	1B52-401D	W-183C	425
1B-40	1B52-403B	W-185A	426
1B-40	1B52-404D	W-181A1	426
1B-40	1B52-404H	W-181A2	426
1B-40	1B52-404M	W-181A3	426
1B-40	1B52-405D	P-206B	425
1B-42	-	1B-42	429
1B-42	1B52-427M	P-012B	417
1B-42	1B52-428M	W-013B2	418
1B-49	1B52-491	D-09	429
1B-49	1B52-494	D-108	428

Note that the safety limit voltage for Unit 1 B-train is being driven by the overcurrent protective device trip current for the service water pumps.

Section III -- Degraded Voltage Analysis

The following is a summary of the voltage at the critical equipment for Unit 2 A-Train contained in Attachment G5:

Bus	Breaker	Equipment ID	Equipment Voltage in Volts
2A-05	2A52-74	2P-015A	391
2B-03	-	2B-03	430
2B-03	2B52-34A	2P-011A	429
2B-03	2B52-34B	P-032F	425
2B-03	2B52-36A	2P-010A	426
2B-03	2B52-38A	2P-014A	428
2B-03	2B52-39A	2W-001A1	422
2B-03	2B52-39B	2W-001B1	423
2B-30	-	2B-30	421
2B-30	2B52-302D	P-207A	420
2B-32	-	2B-32	427
2B-32	2B52-328H	W-013B1	414
2B-32	2B52-328K	W-012D	416
2B-32	2B52-328M	W-012C	416
2B-32	2B52-329H	W-012B	418
2B-32	2B52-3212M	P-012A	417
2B-32	2B52-3213C	W-085	420
2B-39	2B52-391	D-09	427
2B-39	2B52-394	D-107	427

Note that the safety limit voltage for Unit 2 A-train is being driven by equipment minimum voltage requirements.

Section III -- Degraded Voltage Analysis

The following is a summary of the voltage at the critical equipment for Unit 2 B-Train contained in Attachment G6:

Bus	Breaker	Equipment ID	Equipment Voltage in Volts
2A-06	2A52-88	2P-015B	3916
2A-06	2A52-90	P-038B	3921
2B-04	-	2B-04	429
2B-04	2B52-26A	2W-001C1	423
2B-04	2B52-26B	2W-001D1	423
2B-04	2B52-27A	2P-014B	427
2B-04	2B52-27B	P-032D	425
2B-04	2B52-27C	P-032E	424
2B-04	2B52-28B	2P-011B	428
2B-04	2B52-29A	2P-010B	426
2B-40	-	2B-40	431
2B-40	2B52-401B	W-184C	429
2B-40	2B52-401D	W-184B	428
2B-40	2B52-403B	W-185B	430
2B-40	2B52-404D	W-181B1	430
2B-40	2B52-404H	W-181B2	430
2B-40	2B52-404M	W-181B3	430
2B-40	2B52-405D	P-207B	430
2B-42	-	2B-42	427
2B-42	2B52-426J	W-086	419
2B-42	2B52-4211M	W-014B	417
2B-42	2B52-4212B	D-109	425
2B-49	2B52-491	D-08	428

Note that the safety limit voltage for Unit 2 B-train is being driven by the overcurrent protective device trip current for the service water pumps.

The voltages were maintained above all safeguards equipment minimum steady state running voltage at the terminals of the equipment. The steady state MCC voltage remained above 420 V for safeguards buses 1B-32, 2B-32, 1B-42 and 2B-42. Additionally, the battery chargers connected to the system were maintained above 412V. Therefore the Acceptance Criteria III.3.01, III.3.02 and III.3.12 have been satisfied.

In addition, the voltages at the safeguards buses 1B-32, 2B-32, 1B-42 and 2B-42 are greater than the voltages required to support the minimum voltage requirements for safety related MCC control circuits for inrush conditions. Therefore, Acceptance Criteria III.3.13 has been satisfied.

III.7.02 Dynamic Motor Starting Analysis at Minimum 4.16 kV system voltage (Section III.6.04)

The dynamic motor starting analysis was performed for each safeguards buses to ensure that each safeguards motor was capable of starting at the minimum 4.16 kV system voltage. The results are as follows for each bus:

1A-05: The dynamic motor starting analysis is contained in Attachments G9 through G12. The results show that all safeguards motors are capable of starting and coming up to full speed at the minimum 4.16 kV system voltage. The results show that each motor is capable of starting throughout the event. The following is a summary of the worst-case minimum bus voltages taken from the graphs (i.e., the numbers represent the voltages associated with the worst-case voltage dip on the plot and are rounded down to the next lowest 50V for 4.16kV and 5V for 480V):

- 1A-05 maintained greater than 3800 volts
- 1B-03 maintained greater than 380 volts
- 1B-32 maintained greater than 375 volts
- 1B-30 maintained greater than 370 volts
- 1B-39 maintained greater than 380 volts

The 4.16 kV and 480V switchgear bus voltage remained above 78.75% (3276 V) at the 4.16 kV buses and 55% (264 V) at the 480 V buses throughout the event. These values are greater than the 4.16 kV and 480V system loss of voltage relays' maximum dropout voltage. The acceleration times of the safety injection pump motor, residual heat removal pump motor, containment spray pump motors, containment accident fan motors, and the service water pump motors remained within the established starting times required per Acceptance Criteria III.3.05. Therefore, the minimum 4.16 kV system voltage is acceptable and Acceptance Criteria III.3.03, III.3.04 and III.3.05 have been satisfied. Additionally, the minimum MCC voltages remained greater than the required holding voltage for the MCC control circuits. Therefore, Acceptance Criteria III.3.14 has been satisfied.

1A-06: The dynamic motor starting analysis is contained in Attachments G13 through G16. The results show that all safeguards motors are capable of starting and coming up to full speed at the minimum 4.16 kV system voltage. The results show each motor is capable of starting throughout the event. The following is a summary of the worst-case minimum bus voltages taken from the graphs (i.e., the numbers represent the voltages associated with the worst-case voltage dip on the plot and are rounded down to the next lowest 50V for 4.16kV and 5V for 480V):

- 1A-06 maintained greater than 3800 volts
- 1B-04 maintained greater than 380 volts
- 1B-42 maintained greater than 380 volts
- 1B-40 maintained greater than 415 volts
- 1B-49 maintained greater than 380 volts

The 4.16 kV and 480V switchgear bus voltage remained above 78.75% (3276 V) at the 4.16 kV buses and 55% (264 V) at the 480 V buses throughout the event. These voltages are greater than the 4.16 kV and 480V system loss of voltage relays' maximum dropout voltage. The acceleration times of the safety injection pump motor, residual heat removal pump motor, containment spray pump motors, the containment accident fan motors, and the service water pump motors remained within the established starting times required per Acceptance Criteria III.3.05. Therefore, the minimum 4.16 kV system voltage is acceptable and Acceptance Criteria III.3.03, III.3.04 and III.3.05 have been satisfied. Additionally, the minimum MCC voltages remained greater than the required holding voltage for the MCC control circuits. Therefore, Acceptance Criteria III.3.14 has been satisfied.

2A-05: The dynamic motor starting analysis is contained in Attachments G17 through G20. The results show that all safeguards motors are capable of starting and coming up to full speed at the minimum 4.16 kV system voltage. The results show each motor is capable of starting throughout the event. The following is a summary of the worst-case minimum bus voltages taken from the graphs (i.e., the numbers represent the voltages associated with the worst-case voltage dip on the plot and are rounded down to the next lowest 50V for 4.16kV and 5V for 480V):

- 2A-05 maintained greater than 3800 volts
- 2B-03 maintained greater than 380 volts
- 2B-32 maintained greater than 380 volts
- 2B-30 maintained greater than 375 volts
- 2B-39 maintained greater than 380 volts

The 4.16 kV and 480V switchgear bus voltage remained above 78.75% (3276 V) at the 4.16 kV buses and 55% (264 V) at the 480 V buses throughout the event. These voltages are greater than the 4.16 kV and 480V system loss of voltage relays' maximum dropout voltage. The acceleration times of the safety injection pump motor, residual heat removal pump motor, containment spray pump motors, the containment accident fan motors, and the service water pump motors remained within the established starting times required per Acceptance Criteria III.3.05. Therefore, the minimum 4.16 kV system voltage is acceptable and Acceptance Criteria III.3.03, III.3.04 and III.3.05 have been satisfied. Additionally, the minimum MCC voltages remained greater than the required holding voltage for the MCC control circuits. Therefore, Acceptance Criteria III.3.14 has been satisfied.

2A-06: The dynamic motor starting analysis is contained in Attachments G20 through G24. The results show that all safeguards motors are capable of starting and coming up to full speed at the minimum 4.16 kV system voltage. The results show that each motor is capable of starting throughout the event. The following is a summary of the worst-case minimum bus voltages taken from the graphs (i.e., the numbers represent the voltages associated with the worst-case voltage dip on the plot and are rounded down to the next lowest 50V for 4.16kV and 5V for 480V):

- 2A-06 maintained greater than 3800 volts
- 2B-04 maintained greater than 380 volts
- 2B-42 maintained greater than 375 volts
- 2B-40 maintained greater than 420 volts
- 2B-49 maintained greater than 380 volts

The 4.16 kV and 480V switchgear bus voltages remained above 78.75% (3276 V) at the 4.16 kV buses and 55% (264 V) at the 480 V buses throughout the event. These voltages are greater than the 4.16 kV and 480V system loss of voltage relays' maximum dropout voltage. The acceleration times of the safety injection pump motor, residual heat removal pump motor, containment spray pump motors, the containment accident fan motors, and the service water pump motors remained within the established starting times required per Acceptance Criteria III.3.05. Therefore, the minimum 4.16 kV system voltage is acceptable and Acceptance Criteria III.3.03, III.3.04 and III.3.05 have been satisfied. Additionally, the minimum MCC voltages remained greater than the required holding voltage for the MCC control circuits. Therefore, Acceptance Criteria III.3.14 has been satisfied.

III.7.03 Degraded Voltage Dropout and Pickup setpoint (Calculation Section III.6.05)

The drift uncertainty for the ABB 27N relays is $\pm 0.26\%$ of setting based on the statistical analysis performed of the as-found / as-left data from past relay calibrations and is contained in Attachment C.

Technical Specification requirement of ≥3937V:

The nominal and actual settings for the degraded voltage relay dropout setpoint and the associated maximum 4.16 kV system voltage at which the degraded voltage relay would dropout are as follows:

$NTSP_{DO}$ = 113.1 volts

$ATSP_{DO}$ = 113.3 volts

$ATSP_{DO}(max)$ = 113.4 volts

$V_{DO\,Max}$ = 3981 volts

The minimum as-found relay dropout settings for the degraded voltage relay to ensure 95/95 confidence is:

Minimum As-Found (AV): 112.8 volts

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The maximum as-found relay dropout settings for the degraded voltage relay to ensure 95/95 confidence is:

Maximum As-Found drop out $\left(MAF_{DO}^{MAX}\right)$: 113.6 volts

An $NTSP_{DO}$ of 113.1V based on the Technical Specification Allowable Value of 3937V, and including all uncertainty, remains above the required safety limits of 3923V for A-train (1A-05 and 2A-05) and 3927V for B-train (1A-06 and 2A-06).

The nominal and actual settings for the degraded voltage relay pickup setpoint and the associated maximum 4.16 kV system voltage at which the degraded voltage relay would pickup (reset) are as follows:

$NTSP_{PU}$ = 113.7 volts

$ATSP_{PU}$ = 113.9 volts

$ATSP_{PU}(max)$ = 114.0 volts

$V_{SS\,Max}$ = 4002 volts

The minimum as-found relay pickup settings for the degraded voltage relay to ensure 95/95 confidence is:

Minimum As-Found pickup $\left(MAF_{PU}^{MIN}\right)$: 113.4 volts

The maximum as-found relay pickup settings for the degraded voltage relay to ensure 95/95 confidence is:

Maximum As-Found pickup $\left(MAF_{PU}^{MAX}\right)$: 114.2 volts

The $NTSP_{DO}$ setting protects the Technical Specification Allowable value of 3937V to ensure all equipment is maintained above its minimum operating voltage when uncertainty is taken into account. The corresponding $NTSP_{DO}$ setting is 113.1V. This ensures the relays provide a 95% probability with at a 95% confidence level, and Acceptance Criteria III.3.06 will be satisfied.

III.7.04 Minimum 345 kV system voltage (Calculation Section III.6.06)

The minimum allowable 345 kV system voltage required for either one or both HVSATs in service to ensure that the voltage on the 4.16 kV system is equal to or greater than the degraded voltage relays' maximum pickup (reset) of 4002V during steady state conditions is as follows (See Attachments G25 through G28):

For Unit 1: 342,930 (99.4%)

For Unit 2: 343,275 (99.5%)

The 345 kV system voltage must be maintained above 343.5 kV to provide margin above the most limiting voltage. Currently, the minimum allowable 345 kV system voltage is 348.5 kV per Reference VII.6.06. Therefore, Acceptance Criteria III.3.07 has been satisfied.

These values will be re-examined in section III.7.05 for adequacy in the dynamic motor starting analysis.

III.7.05 Dynamic Motor Starting Analysis at Minimum 345 kV system voltage (Section III.6.07)

Dynamic motor starting analyses were performed for each unit to ensure that the degraded voltage relays will not prematurely trip during safeguards motor starts with a loss of coolant accident at the minimum 345 kV system voltage condition. The dynamic motor starting analyses develop the minimum time delay of the degraded voltage relays to ensure that sufficient time is provided to allow the relays to pickup (reset) should bus voltage drop below the relays maximum dropout and return above its pickup during motor starting events. The results are as follows for each unit:

Unit 1:

1. A dynamic motor starting analysis was performed for Unit 1 for a large break LOCA (Plant Configuration L1-1X4) using study cases U1-TD-A and U1-TD-B and are contained in Attachments G29 and G30.
   - The minimum 345 kV system voltage required adjustment. The resulting required voltage is was determined to be 343,965 V (99.7%).
   - The maximum time the voltage dropped below the relays' maximum dropout and returned above the relays' maximum pickup (reset) was 3.3 seconds.

Unit 2:

1. A dynamic motor starting analysis was performed for Unit 2 for a large break LOCA (Plant Configuration L2-2X4) using study cases U2-TD-A and U2-TD-B and are contained in Attachments G31 and G32.
   - The minimum 345 kV system voltage required adjustedment. The required voltage was determined to be 344,310 V (99.8%).
   - The maximum time the voltage dropped below the relay's maximum dropout and returned above the relays' maximum pickup (reset) was 3.2 seconds.

Summary:

The minimum required 345 kV system voltage and the minimum required time delay for the degraded voltage relay are:

Voltage: 344.5 kV for either one HVSAT in service or both HVSATs in service. This value envelopes both operating conditions. The minimum 345 kV system voltage as determined in Section III.7.04 required adjustment as a result of the motor starting analyses.

Minimum Time Delay: 3.3 Seconds, however the analytical limit of 4.6 sec previously determined in Revision 0 of Calculation 2004-0002 was retained in the setting determinations for conservatism.

III.7.06 Evaluation of overcurrent trips of protective devices (Section III.6.08)

The evaluation of the overcurrent tripping times for safety related circuits including the 480V switchgear main breakers and MCC source breakers are determined in Attachment B. The protective devices were evaluated to ensure that (1) the overcurrent protective devices do not trip on overcurrent when voltage equal to or greater than the minimum 4.16 kV system voltage is present, (2) the overcurrent protective devices will not trip when the 4.16 kV system voltage is less than the minimum required, before the degraded voltage relays actuate with a safety injection signal when the motors may be in locked rotor, and (3) the overcurrent protective devices will not trip when the 4.16 kV system voltage is less than the minimum required, before the degraded voltage relays actuate without a safety injection signal when equipment is running at elevated load currents. The following is a summary of the results:

4.16 kV Buses:

1. The safety injection pump motor breakers will not trip at minimum 4.16 kV system voltage.
2. The minimum tripping time is 6 seconds (SI Signal)
3. This calculation imposes a limitation (I.2.02.4) that the protective devices for the new AFW pump motors must be set to trip at a current of at least 50A. In addition, the protective device tripping time at 204A must exceed 7 seconds, and the tripping time at 62A must exceed 50 seconds. This limitation is required to ensure that the AFW pump protective relays will have a margin of at least 2 seconds above the 48 second safety limit (SL_{NSI}).

480V Switchgear:

1. The minimum tripping time is 10 seconds (SI Signal)
2. The minimum tripping time is 50 seconds (without SI Signal)

480V MCCs:

1. No protective devices on the MCCs will trip on overcurrent at the minimum 4.16 kV system voltage.
2. The minimum tripping time required for the MCC protective devices to prevent overcurrent trip is 4.5 seconds. The tripping time is limited by the overload heaters installed in breakers 2B52-328F (SW-02927B – 2B-32) and 2B52-427J (SW-02927A – 2B-42). This does not provide sufficient margin to set the degraded voltage relay's time delay with a safety injection present. Therefore, the next most limiting component with a required minimum tripping time of 6 seconds is utilized.
3. The minimum tripping time is 90 seconds (without SI Signal)

Acceptance Criteria III.3.08 is not maintained for protective devices on circuits 2B52-328F and 2B52-427J because the protective devices may trip on overcurrent during degraded voltage conditions.

The Safety Limit (SL_{NSI}) value of 48 seconds previously determined in Revision 0 of Calculation 2004-0002 is retained for conservatism and to match the Safety Limit value used as the basis for the Technical Specifications.

III.7.07 Degraded Voltage Relay (ABB 27N) time delay setpoint with a safety injection signal.

The drift uncertainty for the ABB 27N relays time delay is ±0.92% of setting based on the statistical analysis performed of the as-found / as-left data from past relay calibrations and is contained in Attachment C.

Technical Specification Allowable Value: ≤ 5.68 seconds

The nominal and actual settings for the degraded voltage relays' time delay setting and the minimum actuation time are as follows:

$NTSP_C = 5.63$ seconds

$ATSP_C = 5.53$ seconds

$MATSP_C = 5.43$ seconds

$TD_C^{min} = 5.15$ seconds

The minimum as-found (MAF_C) relay time delay setting for the degraded voltage relay to ensure 95/95 confidence is <u>5.38 seconds</u>.

The maximum as-found (AV_C) relay time delay setting for the degraded voltage relay to ensure 95/95 confidence is <u>5.68 seconds</u>.

The Technical Specification and settings for the degraded voltage time delay relays with a safety injection signal provide adequate protection to ensure the time delay safety limit of 5.92 seconds is maintained (Acceptance Criteria III.3.10 is met).

As described in Section III.7.06, Acceptance Criteria III.3.09 is not maintained for thermal overload heater protective devices in Cubicles 2B52-328F and 2B52-427J because they may trip within 4.5 seconds.

III.7.08 Degraded Voltage Time Delay Relay (Agastat ETR) without safety injection signal.

The drift uncertainty for the Agastat ETR relays time delay is ±2.75% of setting based on the statistical analysis performed of the as-found / as-left data from past relay calibrations and is contained in Attachment C.

Technical Specification Allowable Value: ≤ 39.14 seconds

The nominal time delay setting for the degraded voltage time delay relay and the minimum actuation time are as follows:

$NTSP_D$ = 38.09 seconds

$ATSP_D$ = 36.99 seconds

$MATSP_D$ = 35.89 seconds

TD_D^{min} = 32.16 seconds

The minimum as-found relay dropout (MAF_D) setting for the degraded voltage time delay relay to ensure 95/95 confidence is 34.90 seconds.

The maximum as-found relay dropout (AV_D) setting for the degraded voltage time delay relay to ensure 95/95 confidence is 39.14 seconds.

The Technical Specification and settings for the degraded voltage time delay relays without a safety injection signal provide adequate protection to ensure that the total time delay safety limit of 48 seconds is maintained (Acceptance Criteria III.3.11).

III.7.09 Potential MOV Stall Time Windows

The potential stall times for safety related MOVs during load sequencing at degraded voltage relay safety limits are tabulated below. The tables show the times at which the MCC voltage drops below 420 V and the duration that the voltage remains below 420 V. No acceptance criteria exists in this calculation for the stall time windows. The stall time values are used as an input to Calculation 97-0041 as described in Section III.8.09.

Bus 1B-32										
Segment	Step #1		Step #2		Step #3		Step #4		Step #5	
	Time (Sec.)	Duration (Sec.)	Time (Sec.)	Duration (Sec.)	Time (Sec.)	Duration (Sec.)	Time (Sec.)	Duration (Sec.)	Time (Sec.)	Duration (Sec.)
A	0	3.4	5.25	0.75	10.14	1.96	-	-	-	-
B	-	-	5.5	0.7	15.02	1.58	-	-	-	-
C	-	-	5.5	0.5	16.02	1.28	19.88	1.52	-	-
D	-	-	5.5	0.2	15.5	1.2	21.17	1.33	38.26	13.44

Bus 1B-42										
Segment	Step #1		Step #2		Step #3		Step #4		Step #5	
	Time (Sec.)	Duration (Sec.)	Time (Sec.)	Duration (Sec.)	Time (Sec.)	Duration (Sec.)	Time (Sec.)	Duration (Sec.)	Time (Sec.)	Duration (Sec.)
A	0	0.4	5.25	0.75	10.14	1.36	-	-	-	-
B	-	-	5.5	0.5	15.02	1.48	-	-	-	-
C	-	-	5.5	0.4	16.02	1.28	19.88	1.32	-	-
D	-	-	5.5	0.1	15.5	1.3	-	-	38.26	12.84

Bus 2B-32										
Segment	Step #1		Step #2		Step #3		Step #4		Step #5	
	Time (Sec.)	Duration (Sec.)	Time (Sec.)	Duration (Sec.)	Time (Sec.)	Duration (Sec.)	Time (Sec.)	Duration (Sec.)	Time (Sec.)	Duration (Sec.)
A	0	2.3	5.25	0.85	10.14	1.96	-	-	-	-
B	0	1.1	5.5	0.8	19.88	1.32	-	-	-	-
C	-	-	5.5	0.7	-	-	24.99	1.51	-	-
D	-	-	5.5	0.5	-	-	26.57	1.33	38.26	13.94

Bus 2B-42										
Segment	Step #1		Step #2		Step #3		Step #4		Step #5	
	Time (Sec.)	Duration (Sec.)	Time (Sec.)	Duration (Sec.)	Time (Sec.)	Duration (Sec.)	Time (Sec.)	Duration (Sec.)	Time (Sec.)	Duration (Sec.)
A	0	2.9	5.25	0.75	10.14	1.96	-	-	-	-
B	-	-	5.5	0.7	19.88	1.72	-	-	-	-
C	-	-	5.5	0.4	21.17	1.43	24.99	1.71	-	-
D	-	-	5.5	0.1	20.5	1.4	26.57	1.43	38.26	13.54

Note: The voltage profile plots for MCC 1B-32 are in Attachments G9 through G12, MCC 1B-42 are in Attachments G13 through G16, MCC 2B-32 are in Attachments G17 through G20, and MCC 2B-42 are in Attachments G21 through G24.

III.7.10 Static Motor Starting Analysis for Balance of Plant 4kV Motors.

The static motor starting analysis for the RCP, feedwater, and condensate motors was performed as described in section III.6.10. The switchyard voltage was set at 98% which is below the minimum acceptable switchyard voltage listed in sections III.7.04 and III.7.05. The ETAP output reports from these analyses are located in Attachments G35 through G37. The voltage supplied to all of the motors remains above 80% of the rated terminal voltage of the motor during starting. These results are acceptable.

III.8 CONCLUSIONS

The conclusions drawn in this section are contingent upon limitations I.2.01.2 through I.2.01.12 being met. If any of these limitations are not met, one of more of the conclusions drawn in this section may not be met.

Revision 2 of Calculation 2004-0002 (Ref. VII.1.27) imposed a limitation (I.2.02.3) on the AFW modifications that the charging pump variable frequency drive (VFD) modifications for all 6 charging pumps are installed and accepted prior to acceptance of the AFW modifications. This limitation is also valid for this calculation.

Revision 2 of Calculation 2004-0002 (Ref. VII.1.27) imposed a limitation (I.2.02.4) that the protective devices for the new AFW pump motors must be set to trip at a current of at least 50A. In addition, the protective device tripping time at 204A must exceed 7 seconds, and the tripping time at 62A must exceed 50 seconds. This limitation is required to ensure that the AFW pump protective relays will have a margin of at least 2 seconds above the 48 second safety limit (SL_{NSI}). This limitation is also valid for this calculation.

III.8.01 Minimum 4.16 kV system voltage

The minimum voltage of the 4.16 kV system was determined to ensure all equipment are maintained equal to or greater than their minimum allowable continuous running voltage at the terminals of the equipment. Safeguards MCCs 1B-32, 2B-32, 1B-42 and 2B-42 were maintained above 420V as required to support MOV operation. The voltage at these MCCs was maintained above the minimum required voltage for control circuit pull in. Acceptance Criteria III.3.01, III.3.02, III.3.12, and III.3.13 have been satisfied.

III.8.02 Dynamic motor starting analysis at minimum 4.16 kV system voltage

The dynamic motor starting analysis demonstrated that all safety related motors were capable of starting throughout the worst-case sequence of events and all equipment was maintained above 75% voltage. The safeguards 4.16 kV switchgear buses were maintained above 3276V and the 480V switchgear buses were maintained above 264V to ensure the loss of voltage protection scheme does not actuate. The safety injection pump motors (P-015), residual heat removal pump motors (P-010), containment spray pump motors (P-014), containment accident fan motors (W-001), and the service water pump motors (P-032) were maintained within the required motor starting times. Acceptance Criteria III.3.03, III.3.04, and III.3.05 have been satisfied. In addition, the minimum MCC voltages remained greater than the required holding voltage for the MCC control circuits and Acceptance Criteria III.3.14 is satisfied.

III.8.03 Degraded voltage relays dropout and pickup setpoint

The degraded voltage relays dropout and pickup setpoints were determined. The required settings have been established to ensure a 95% probability with a 95% confidence level to ensure the 4.16 kV minimum voltage level is maintained and that Acceptance Criteria III.3.06 is satisfied.

III.8.04 Minimum 345 kV system voltage

The minimum voltage for the 345 kV system was determined to ensure that the 4.16 kV steady state voltage was maintained above the degraded voltage pickup setting. This reduces the probability of the safeguards buses separating from offsite power. Acceptance Criterion III.3.07 is satisfied for system alignments where both HVSATS are in service.

III.8.05 Dynamic motor starting analysis at minimum 4.16 kV system voltage

The dynamic motor starting analysis performed in section III.7.04 demonstrated that the degraded voltage relays would not prematurely trip from offsite power. Acceptance criteria III.3.09 and III.3.10 are satisfied.

III.8.06 Evaluation of overcurrent trips of protective devices

The maximum allowable trip times that would prevent premature trip of the protective devices during a degraded voltage condition were established. These trip times were used to establish the maximum allowable degraded voltage time delay relay settings with a safety injection signal and without a safety injection signal. It was determined that circuits 2B52-328F and 2B52-427J would trip on overcurrent and would not satisfy Acceptance Criteria III.3.08 and III.3.09. AR00889745 was initiated to document the condition that the subject protective devices do not meet Acceptance Criteria III.3.08 and III.3.09. The breakers identified in this major revision as failures have already been captured via AR00889745, which was initiated under major Revision 0 to document the condition that the subject protective devices do not meet Acceptance Criteria III.3.08 and III.3.09. No new failures are being identified by this revision, and no new action requests are required.

Revision 2 of Calculation 2004-0002 (Ref. VII.1.27) imposed a limitation (I.2.02.4) that the protective devices for the new AFW pump motors must be set to trip at a current of at least 50A. In addition, the protective device tripping time at 204A must exceed 7 seconds, and the tripping time at 62A must exceed 50 seconds. This limitation is required to ensure that the AFW pump protective relays will have a margin of at least 2 seconds above the 48 second safety limit (SL_{NSI}). Limitation I.2.02.4 remains valid for this calculation.

III.8.07 Degraded Voltage Relay (ABB 27N) time delay setpoint with a safety injection

The degraded voltage relays (ABB 27N) time delay setpoints were determined. The required settings have been established to ensure a 95% probability with a 95% confidence level to ensure that the time delay prevents protective devices overcurrent trip and Acceptance Criteria III.3.10 is satisfied. The Technical Specification Allowable Value and time delay settings satisfy Acceptance Criteria III.3.10.

III.8.08 Degraded Voltage Time Delay Relay (Agastat ETR) setpoint without a safety injection

The degraded voltage time delay relays (Agastat ETR) setpoints were determined. The required settings have been established to ensure a 95% probability with a 95% confidence level to ensure that the time delay prevents protective devices overcurrent trip and equipment damage. The new Technical Specifications Allowable Value settings ensure that the safeguards equipment are not damaged or their protective devices do not prematurely trip. Acceptance Criteria III.3.11 has been satisfied.

III.8.09. Potential MOV Stall Time Windows

The potential stall times for safety related MOVs during load sequencing at degraded voltage relay safety limits were determined and are tabulated in Section III.7.09. AR01115662 has been initiated to revise Calculation 97-0041 to incorporate the additional time delay or perform additional analysis of the MOVs. The values used for AR01115662 were developed by revision 2 of Calculation 2004-0002 (Ref. VII.1.27). The values from this revision are bounded by the values found in Reference VII.1.27. Therefore, the revision to calculation 97-0041 resulting from AR01115662 bounds any changes that would be required by this calculation.

III.8.10 Static Motor Starting Analysis for Balance of Plant 4 kV Motors

The terminal voltage for all balance of plant motors evaluated remains above 80% of the rated voltage when starting. Acceptance criteria III.3.15 is satisfied.

IV EMERGENCY DIESEL GENERATOR STEADY STATE LOADING ANALYSIS

The purpose of this calculation is to perform steady state loading analysis of the safety related 4160V and 480V systems being supplied by the alternate emergency standby power source after a loss of offsite power (LOOP). The analysis will determine whether each emergency diesel generator (G-01, G-02, G-03, and G-04) is capable of supplying the power requirements of one complete set of safeguards equipment for one unit having a loss of coolant accident (safety injection) and also providing sufficient power to place the second unit in a safe shutdown condition.

The analysis includes an evaluation of the emergency diesel generator's (EDG's) ability to support both the automatically loaded and the manually added loads prior to entering the EDG load management procedures by plant operators. In addition, this calculation section demonstrates that the EDGs are capable of supplying the required manually added loads (e.g. CCW, battery chargers, control room ventilation) after entering the EDG load management procedures by plant operators.

This calculation also determines:

- The maximum and minimum allowable voltage settings for the EDGs to ensure that all equipment will operate satisfactorily within their acceptable voltage ranges.
- The required loading (kW) values associated with the optional loads that may be added by Plant Operators utilizing the EDG load management procedures to support management of the load placed on the EDGs.

METHODOLOGY

The following steps are used to develop the worst-case total EDG steady state loading, to determine the EDG's minimum and maximum allowable output voltage to ensure all equipment will operate under LOOP conditions, and to evaluate EDG Load Management.

Step 1 - AC Electrical Distribution System Model

The AC electrical distribution system model is developed and contains the technical data, equipment demand factors, and operating (e.g. ON/OFF, brake horsepower, etc.) status for plant equipment from the 345 kV system through the 480 V system in ETAP. The ETAP model will be used to determine the EDG steady state loading as well as to determine the EDG minimum output voltage limit. The maximum voltage limit will be determined from the ratings of the EDGs and loads without using ETAP.

Step 2 - Plant Operating Conditions (Scenarios/Cases)

The EDG steady state loading analysis evaluates the 4160V and 480V system being supplied by the EDGs following a LOOP. The different plant operating conditions (scenarios) are evaluated to determine the worst-case plant conditions. The operating conditions in which the EDGs are required to operate to supply emergency stand-by power are as follows: (1) The EDGs supplying power with one unit in mode 3 following a

LOCA and the other unit in shutdown (modes 3, 4, 5, 6 or defueled – see discussion below) concurrent with a LOOP in both units. (2) The EDGs supplying power to both units shut down (modes 3, 4, 5, 6 or defueled) with a LOOP in both units; and (3) for the shut down unit in mode 6 or defueled with the B03/B04 cross-tie breaker closed.

Although the EDGs are normally aligned so that each EDG will feed its associated safety train for a single unit (G-01 normally supplies emergency power to 1A-05, G-02 normally supplies emergency power to 2A-05, G-03 normally supplies emergency power to 1A-06 and G-04 normally supplies emergency power to 2A-06), the PBNP licensing basis requires that a single EDG can support the loading required to safely shut down both units. Aligning each diesel to support both units for this analysis places the plant in the most limiting design basis power supply configuration, and results in the highest design basis load on the EDGs. The EDGs are designed to provide the necessary power to cool the core and maintain containment pressure within the design value for a loss of coolant accident in addition to supplying sufficient power to shut down the unaffected unit (no accident is assumed in the second unit) coincident with a loss of offsite power to both units. Therefore, each EDG is required to be capable of supplying power to one complete set of safeguards equipment for one reactor unit and allow the second reactor unit to be placed in a safe shutdown condition.

The plant operating conditions evaluated for each EDG for the LOCA are based on the injection phase of the event. Plant operators enter AOP-22 and begin managing the EDG load during the injection phase of the LOCA. Load management continues through the transition from injection to recirculation and throughout the recirculation phase of the event. EDG load management and evaluation during the recirculation phase of the LOCA event is discussed later.

For the purposes of this calculation section, the non-accident (shut down) unit may be in modes 3, 4, 5, 6, or defueled. The automatic loading in the shut down unit is the same whether the unit is in mode 3, 4, 5, 6, or defueled. In mode 3, the Auxiliary Feedwater (AFW) system provides core cooling via the steam generators, and RHR is not used. In modes 4, 5, and 6, an RHR pump (200 hp) must be manually started following a LOOP to restore shutdown cooling. In these modes, the motor driven AFW pump in the shut down unit will start automatically as a result of the SI signal in the opposite unit. Therefore, the unit is modeled in modes 4, 5, or 6 to establish the worst case EDG loading since RHR and AFW will be required.

The plant operating conditions being evaluated are consistent with plant operating procedures, design bases events and licensing commitments to ensure the worst-case conditions are evaluated for EDG steady state loading. The following are the plant operating scenarios to be evaluated for EDG steady state loading and their supporting basis.

Case 50: This case models Unit 1 in mode 3 due to a unit trip because of a large break LOCA concurrent with a LOOP, and Unit 2 shut down when the LOOP occurs. EDG G-01 is connected to both 1A-05 and 2A-05; and G-03 is connected to both 1A-06 and 2A-06. This case models only the automatic loads connected to the EDG as "ON", all remaining loads are modeled as "OFF". This provides the worst-case automatic loading conditions for the A-train and B-train EDGs for a Unit 1 LOCA. This case provides the maximum automatic loading on an individual EDG based on a failure of the opposite train's safeguards EDGs. All 4.16 kV and 480 V bus ties are modeled as OPEN.

Case 51: This case models Unit 1 in mode 3 due to a unit trip because of a large break LOCA concurrent with a LOOP, and Unit 2 shut down when the LOOP occurs. EDG G-01 is connected to both 1A-05 and 2A-05; and G-03 is connected to both 1A-06 and 2A-06. This case models the automatic loads connected to the EDG as "ON". In addition, manual loads 2P-010A and 2P-010B (which are manual loads added to the EDG by plant operators prior to entering the EDG load management procedures) are modeled as "ON". All remaining loads are modeled as "OFF". This provides the worst-case loading conditions on an individual EDG considering both automatic and manual loading for A-train and B-train EDGs for a Unit 1 LOCA based on a failure of the opposite train's safeguards EDGs. This case provides the maximum loading on an individual EDG based on a single failure of the opposite train's safeguards EDG prior to entering the EDG load management procedures by plant operators. All 4.16 kV and 480 V bus ties are modeled as OPEN.

Case 52: This case models Unit 2 in mode 3 due to a unit trip because of a large break LOCA concurrent with a LOOP, and Unit 1 shut down when the LOOP occurs. EDG G-02 is connected to both 1A-05 and 2A-05; and G-04 is connected to both 1A-06 and 2A-06. This case models only the automatic loads connected to the EDG as "ON", all remaining loads are modeled as "OFF". This provides the worst-case automatic loading conditions for A-train and B-train EDGs for a Unit 2 LOCA. This case provides the maximum automatic loading on an individual EDG based on a failure of the opposite train's safeguards EDG. All 4.16 kV and 480 V bus ties are modeled as OPEN.

Case 53: This case models Unit 2 in mode 3 due to a unit trip because of a large break LOCA concurrent with a LOOP, and Unit 1 shut down when the LOOP occurs. EDG G-02 is connected to both 1A-05 and 2A-05; and G-04 is connected to both 1A-06 and 2A-06. This case models the automatic loads connected to the EDG as "ON". In addition, manual loads 1P-010A and 1P-010B (which are manual loads added to the EDG by plant operators prior to entering the EDG load management procedures) are modeled as "ON". All remaining loads are modeled as "OFF". This provides the worst case loading conditions on an individual EDG considering both automatic and manual loading for A-train and B-train EDGs for at Unit 2 LOCA based on a failure of the opposite train's safeguards EDGs. This case provides the maximum loading on an individual EDG based on a single failure of the opposite train's safeguards EDG prior to entering the EDG load management procedures by plant operators. All 4.16 kV and 480 V bus ties are modeled as OPEN.

Case 54: This case models Unit 1 in mode 3 due to a unit trip because of a large break LOCA concurrent with a LOOP, and Unit 2 in modes 5, 6, or defueled as required by Technical Specifications 3.8.9 and 3.8.10 (References VII.8.18 and VII.8.19) when 480 V bus ties on the opposite unit are closed, when the LOOP occurs. EDG G-01 is connected to both 1A-05 and 2A-05; and G-03 is connected to both 1A-06 and 2A-06. This case models only the automatic loads connected to the EDG as "ON", all remaining loads are modeled as "OFF". In addition, prior to the event 480V bus tie breaker 2B52-40C is CLOSED, while supply breakers 2A52-89 and 2B52-25B are OPEN and 2B-03 is supplying power to 2B-04 with the required load limitation that 2P-011B, P-032D and P-032E are out-of-service. The single failure considered is that bus tie breaker 2B52-40C fails to open upon receipt of the undervoltage signal. This provides the worst-case loading conditions considering both automatic loading for A-train EDGs for a Unit 1 LOCA and the Unit 2 480V bus tie breaker closed. This case provides the maximum loading on an A-train EDG based on the single failure of the 480V bus tie breaker to open on an undervoltage signal. In this case, A-train and B-train EDGs are available to supply necessary loads that need to be manually started in both units.

Case 55: This case models Unit 1 in mode 3 due to a unit trip because of a large break LOCA concurrent with a LOOP, and Unit 2 in modes 5, 6, or defueled as required by Technical Specifications 3.8.9 and 3.8.10 when 480 V bus ties on the opposite unit are closed, when the LOOP occurs. EDG G-01 is connected to both 1A-05 and 2A-05; and G-03 is connected to both 1A-06 and 2A-06. This case models only the automatic loads connected to the EDG as "ON", all remaining loads are modeled as "OFF". In addition, prior to the event 480V bus tie breaker 2B52-40C is CLOSED, while supply breakers 2A52-75 and 2B52-40B are OPEN and 2B-04 is supplying power to 2B-03 with the required load limitation that 2P-011A and P-032F are out-of-service. The single failure considered is that bus tie breaker 2B52-40C fails to open upon receipt of the undervoltage signal. This provides the worst-case loading conditions considering both automatic loading for B-train EDGs for a Unit 1 LOCA and the Unit 2 480V bus tie breaker closed. This case provides the maximum loading on a B-train EDG based on the single failure of the 480V bus tie breaker to open on an undervoltage signal. In this case, A-train and B-train EDGs are available to supply necessary loads that need to be manually started in both units.

Case 56: This case models Unit 2 in mode 3 due to a unit trip because of a large break LOCA concurrent with a LOOP, and Unit 1 in modes 5, 6, or defueled as required by Technical Specifications 3.8.9 and 3.8.10 when 480 V bus ties on the opposite unit are closed, when the LOOP occurs. EDG G-02 is connected to both 1A-05 and 2A-05; and G-04 is connected to both 1A-06 and 2A-06. This case models only the automatic loads connected to the EDG as "ON", all remaining loads are modeled as "OFF". In addition, prior to the event 480V bus tie breaker 1B52-16C is CLOSED, while supply breakers 1A52-84 and 1B52-17B are OPEN and 1B-03 is supplying power to 1B-04 with the required load limitation that 1P-011B and P-032C are out-of-service. The single failure considered is that bus tie breaker 1B52-16C fails to open upon receipt of the undervoltage signal. This provides the worst-case loading conditions considering both automatic loading for A-train EDGs for a Unit 2 LOCA and the Unit 1 480V bus tie breaker closed. This case provides the maximum loading on an A-train EDG based on the single failure of the 480V bus tie breaker to open on an undervoltage signal. In this case, A-train and B-train EDGs are available to supply necessary loads that need to be manually started in both units.

Case 57: This case models Unit 2 in mode 3 due to a unit trip because of a large break LOCA concurrent with a LOOP, and Unit 1 in modes 5, 6, or defueled as required by Technical Specifications 3.8.9 and 3.8.10 when 480 V bus ties on the opposite unit are closed, when the LOOP occurs. EDG G-02 is connected to both 1A-05 and 2A-05; and G-04 is connected to both 1A-06 and 2A-06. This case models only the automatic loads connected to the EDG as "ON", all remaining loads are modeled as "OFF". In addition, prior to the event 480V bus tie breaker 1B52-16C is CLOSED, while supply breakers 1A52-58 and 1B52-16B are OPEN and 1B-04 is supplying power to 1B-03 with the required load limitation that 1P-011A, P-032Aand P-032B are out-of-service. The single failure considered is that bus tie breaker 1B52-16C fails to open upon receipt of the undervoltage signal. This provides the worst-case loading conditions considering both automatic loading for B-train EDGs for a Unit 2 LOCA and the Unit 1 480V bus tie breaker closed. This case provides the maximum loading on a B-train EDG based on the single failure of the 480V bus tie breaker to open on an undervoltage signal. In this case, A-train and B-train EDGs are available to supply necessary loads that need to be manually started in both units.

Case 58: This case models Unit 1 and Unit 2 shut down in modes 5, 6 or defueled as required by Technical Specifications 3.8.9 and/or 3.8.10 for a shut down unit when 480 V bus ties are closed, when the LOOP occurs in both units. This case is evaluating each unit independently. The automatic load on the EDGs is based on the ESF loading that would occur in a shut down unit when the other unit has a LOCA in order to provide the worst-case loading on the non-accident unit as a result of the common system loads. Therefore, the status of the equipment in both units is based on a LOCA in the opposite unit in developing the loading on the safeguard buses. EDG G-01 is connected to 1A-05, G-02 is connected to 2A-05; G-03 is connected to 1A-06 and G-04 is connected to 2A-06. This case models only the automatic loads connected to the EDG as "ON", all remaining loads are modeled as "OFF". In addition, prior to the event 480V bus tie breaker 1B52-16C is CLOSED, while supply breakers 1A52-84 and 1B52-17B are OPEN, and 1B-03 is supplying power to 1B-04. 480V bus tie breaker 2B52-40C is CLOSED, while supply breakers 2A52-89 and 2B52-25B are OPEN, and 2B-03 is supplying power to 2B-04. No loading limitations are required for this alignment. The single failure considered for each train evaluated in this case is that bus tie breakers 1B52-16C and 2B52-40C fail to open upon receipt of the undervoltage signal. This provides the worst-case loading conditions for automatic loading on the A-train EDGs for Unit 1 or Unit 2 shut down in modes 5, 6 or defueled with the Unit 1 or Unit 2 480 V bus tie breaker closed and the EDG aligned to a single unit. This case provides the maximum loading on an A-train EDG based on a single failure of a 480 V bus tie breaker failing to open on an undervoltage signal.

Case 59: This case models Unit 1 and Unit 2 shut down in modes 5, 6 or defueled as required by Technical Specifications 3.8.9 and/or 3.8.10 for a shut down unit when 480 V bus ties are closed, when the LOOP occurs in both units. This case is evaluating each unit independently. The automatic load on the EDG is based on the ESF loading that would occur in a shut down unit when the other unit has a LOCA in order to provide the worst-case loading on the non-accident unit as a result of the common system loads. Therefore, the status of the equipment in both units is based on a LOCA in the opposite unit in developing the loading on the safeguard buses. EDG G-01 is connected to 1A-05, G-02 is connected to 2A-05; G-03 is connected to 1A-06 and G-04 is connected to 2A-06. This case models only the automatic loads connected to the EDG as "ON", all remaining loads are modeled as "OFF". In addition, prior to the event 480V bus tie breaker 1B52-16C is CLOSED, while supply breakers 1A52-58 and 1B52-16B are OPEN, and 1B-04 is supplying power to 1B-03. 480V bus tie breaker 2B52-40C is CLOSED, while supply breakers 2A52-75 and 2B52-40B are OPEN and 2B-04 is supplying power to 2B-03. No loading limitations are required for this alignment. The single failure considered for each train evaluated in this case is that bus tie breakers 1B52-16C and 2B52-40C fail to open upon receipt of the undervoltage signal. This provides the worst-case loading conditions for automatic loading on the B-train EDGs for Unit 1 or Unit 2 shut down in modes 5, 6, or defueled with the Unit 1or Unit 2 480 V bus tie breaker closed and the EDG aligned to a single unit. This case provides the maximum loading on a B-train EDG based on a single failure of a 480 V bus tie breaker failing to open on an undervoltage signal.

Step 3 - Emergency Diesel Generator Load Addition To Account For Frequency Tolerance

The EDGs operate at a nominal frequency of 60 Hz, however the frequency of the system is dependent on the operation of the EDG governor, which controls the output frequency of the EDG. The EDG governor setpoint and plant operating procedures ensure that the EDG is maintained at an operating frequency of 60 ± 0.3 Hz. The operating frequency of the system impacts the power demands of centrifugal pumps and fans as a result of the speed change of the equipment. The power demands of centrifugal pumps and fans change as a cube of the ratio of the speeds based on the mechanical affinity laws.

The EDG steady state loading analysis evaluates the EDG loading equivalent to the power demand at a frequency deviation of + 0.3 Hz, which will increase the power demand of the centrifugal pumps and fans in the system. Therefore based on the mechanical affinity law, an increase of 101.5% must be included for the centrifugal pumps and fans powered by the EDG for the purposes of EDG steady state loading.

Step 4 - Development of Study Cases for EDG Steady State Loading Analysis

The study case for each type of analysis within ETAP (including EDG steady state loading) contains, as applicable, the solution control variables, loading conditions, tolerance adjustments, load diversity factors and a variety of options for output reports. The set-up for the EDG steady state loading analysis study case options are developed and the specific options chosen for the EDG steady state loading analysis are discussed below:

Loading Category – "Max EDG": The maximum EDG demand factor loading category is conservatively chosen because it provides the worst case loading on the system and therefore provides the worst-case loading onto the EDGs. The maximum brake horsepower (BHP) of the loads are used.

Generation Category – "Min Voltage": The generation category of "Min Voltage" is chosen to perform the EDG steady state loading analysis. The EDG steady state loading analysis will utilize this category to determine the voltage at downstream loads when the EDGs are operating at the minimum allowable output voltage.

Resistance Temperature Correction – "Cable – Individual Max Temperature": The conductor temperature used for the cable impedance used to determine the EDG steady state loading is developed. The conductor temperature used for the EDG steady state loading is 90 °C. The 90 °C temperature is conservative because higher conductor temperatures result in higher cable losses, which is conservative for EDG steady state loading.

Load Diversity Factor – "Global – Constant KVA": An increase in the power demand for induction motors supporting centrifugal pumps and fans occurs as a result of the positive frequency variation (increase) of the EDG. Therefore, to account for the increased power demand the "Global – Constant KVA" load diversity factor is utilized to increase the demand for all constant KVA loads (e.g. induction motors). This is conservative because the entire EDG constant KVA load will be treated as frequency dependent similar to a pump and fan, where the load increases as the cube of frequency. However, not all of the constant KVA loads are frequency dependent (e.g., battery chargers). The "Global – Constant KVA" load diversity factor entered in ETAP is conservatively increased to 102% since ETAP will not accept more than 3 characters in the global demand factor field. It should be noted that the 102% value corresponds to a frequency deviation of 0.4 Hz. The additional kW added will offset the station service transformer (1X-13, 1X-14, 2X-13 or 2X-14) no-load (excitation) losses, which are not specifically modeled.

Load Diversity Factor – "Global – Constant Z": The maximum steady state loading on the EDG is to be determined throughout the entire operating range of the EDG. The power demand of constant impedance (static) loads in the system is directly proportional to the square of the system voltage, and the resulting maximum load for constant impedance loads would occur at the maximum EDG voltage. The power demand associated with constant KVA loads (e.g., motors) remains constant throughout the EDG output voltage range except for changes in cable losses as a result of current being inversely proportional to system voltage. Therefore, to limit the total number of ETAP runs required, the overall static load is increased by using a global demand factor for all static loads. Since static load power is proportional to the square of voltage, the global demand factor is set the square of the maximum to minimum EDG voltage. This will allow the same ETAP runs to be used both for determining the minimum allowable EDG voltage and the overall EDG steady state loading. The approach is conservative for determining the minimum allowable EDG output voltage because the increased loading increases losses in the cables and transformers feeding the loads, thus producing lower voltages at the buses used to determine when the minimum allowable voltage is reached. Since the static load represents a small portion of the overall load, this approach will not add an undue amount of additional conservatism for either evaluation.

Step 5 - Establish Emergency Diesel Generator Derated KW Ratings

The EDGs load ratings are based on a certain air intake (combustion air) temperature and a given maximum engine coolant temperature. The manufacturer provides engine derating factors at elevated temperatures as a % of the standard (90 °F) intake air temperature. The purpose of the curves is to determine the maintenance intervals at higher air intake (combustion air) temperature. If the temperature limits are exceeded, then the load ratings may be reduced to maintain the original maintenance intervals, or the maintenance intervals shortened to accommodate the originally stated power levels (i.e., a constant kW-hr value). For the purposes of this calculation, the A-train EDG kW ratings are retained for the existing maintenance intervals. For the purposes of this calculation, the B-train EDG maintenance intervals are shortened to accommodate the originally stated kW values. The calculated values for EDG steady state loading will be compared to the appropriately derated kW values to determine whether the EDGs have the capability to supply the required loads at the maximum expected intake air temperatures.

G-01 and G-02 Load Ratings

Intake Air Temperature: 115 °F
Coolant Temperature: 190 °F

Standard Rating		Derated kW	Derate Factor
Time	kW		
2000 hr	2850	2850	1.000
200 hr	See Note	See Note	See Note
4 hr	See Note	See Note	See Note
30 min	3050	2958	.970

Note: With an intake air temperature of 115 °F, the engine cannot support a kW loading above 2850 kW for the desired maintenance intervals for the 200 and 4 hour ratings. Therefore, the EDG must remain within the 2000 Hr rating.

G-03 and G-04 Load Ratings

Intake Air Temperature: 95 °F
Coolant Temperature: 190 °F

Standard Rating		Derated Time	Derate Factor
Time	kW		
2000 hr	2848	2850	1.000
200 hr	2951	195 hr	0.986
4 hr	2987	3.75 hr	0.986
30 min	N/A	N/A	0.994

The 197.2 and 3.94 hour values corresponding to the standard (original) 200 hour and 4 hour ratings, respectively, will be conservatively rounded down to 195 hours and 3.75 hours respectively for conservatism.

Step 6 - Determination of EDG Steady State Loading and Minimum EDG Voltage

The EDG steady state loading analysis is to establish the maximum loading on the EDG during the worst-case plant conditions and to establish the minimum EDG output voltage requirements to ensure that all safety related equipment in the 4160V and 480V systems have sufficient voltage to perform their design function during a Design Basis Event (e.g. LOCA).

The maximum EDG kW loading and the minimum EDG output voltage is calculated by utilizing ETAP load flow analysis module and the AC Electrical System Model. Case 50 through 59 will be used to determine the kW loading of the EDG for the defined plant configuration and determine the minimum allowable EDG output voltage. The minimum allowable EDG output voltage is defined as the lowest EDG output voltage that allows the licensing basis required equipment to meet the acceptance criteria without going below the EDG minimum rated output voltage. An iterative process will determine the minimum EDG output voltage by updating the associated generating category – voltage for the EDG (G-01, G-02, G-03 and/or G-04) until the minimum steady state voltage criteria for all safety related equipment supplied by the EDG is satisfied. Essentially, the most limiting safety related component would be at its minimum voltage rating. The Newton Raphson iterative technique is used to calculated the EDG kW loading and the equipment voltages for each condition evaluated. The load flow study cases and their associated options are discussed in Step 4 above. The generation category "Min Voltage" will be utilized for the associated EDG for each condition evaluated.

The generator rated kVA and power factor are compared to the calculated generator MVA and power factor values in the ETAP load flow report for each case. The manually added loads are evaluated separately using standard complex arithmetic and trigonometry to convert from kW and power factor to kVA and kVAR as necessary.

The minimum allowable EDG output voltage for equipment operability will be compared to the minimum rated generator output voltage (95%) to confirm that the machine rated minimum voltage bounds (is lower than) the voltage required for downstream equipment operability.

Step 7 - Determination of Maximum EDG Voltage

The EDG steady state loading analysis will establish the maximum allowable EDG output voltage to ensure that all safety related equipment in the 4160V and 480V systems are within their maximum voltage rating to ensure they will perform their design function during a Design Basis Event (e.g., LOCA).

The maximum system voltage within the safety related system will be manually calculated based on the maximum rated EDG output voltage (105%). The system voltages will be determined by conservatively ignoring the voltage drop between the EDG and the equipment and calculated based on the applicable transformer voltage ratios within the system. The maximum system voltage will be compared to the maximum rated voltage of the safety related utilization equipment only (the non safety related equipment is addressed further below). If the maximum rated voltage of the utilization equipment is below the maximum voltage of the generator, no further analysis or ETAP runs are required. The comparisons will be made using rated equipment voltages, simple transformer voltage ratios and percentages of the nominal voltages.

Step 8 - Determination of KW Values for EDG Load Management

Plant operators manage the load on the EDGs by following the EDG load management procedures. The EDG load management procedures allow the plant operators to add and subtract load on the EDG, however the EDG must remain within its specified rating. Therefore, to support the management of EDG load, the maximum kW loading values for manually added loads are determined. The maximum kW loading values are provided to establish the maximum potential kW load value that would be loaded onto the EDG upon load energization to prevent overloading of the EDG.

The individual equipment loading values (kW) for loads listed in the Emergency Operating Procedures that may be added to the EDGs under the guidance of AOP-22 Unit 1 or AOP-22 Unit 2 are calculated from the equipment nameplate ratings in the master input calculations in most cases and applying the maximum demand factor for each load. For the purpose of conservatism in this calculation, MCC loads will be calculated with a 100% demand factor even if the actual demand factor is less than 100%. The rated kW value for motor loads will be calculated from the rated voltage, current and power factor of the motor using a standard engineering formula.

The rated kW will be scaled by the ratio of the actual demand horsepower to the motor's rated horsepower to account for the expected motor loading.

For motor loads, the kW loading will be corrected to increase the loading value by 102% to account for the impact of EDG frequency.

To account for additional losses in the distribution system, one additional kW will be added for loads less than 50 kVA or 50 hp. Two additional kW will be added for loads 50 kVA or 50 hp and larger. The 1 and 2 kW values are an engineering judgment based on a review of the ETAP output reports for Cases 50 through 59. Cable losses for circuits feeding motors are nearly all less than 2 kW, and less than 1 kW for all smaller motors. In either case, the calculated kW value will be rounded up to the next higher full kW.

The individual loading for transformer and static loads will be based on the KVA rating of the equipment and conservatively consider the load as having a unity power factor, so that 1 kVA = 1 kW. No efficiency values are required. As with motors, one kW will be added for loads smaller than 50 kVA, and two kW will be added for loads 50 kVA or larger to account for additional distribution system losses, and the calculated kW value will be rounded up to the next higher full kW.

Battery charger loads are a special case. The chargers will be in current limit when initially picked up, and the load will gradually decrease as the battery is recharged. For the purposes of this analysis, the charger load will be taken as the kW value at the current limit setting of the chargers. The kW value for chargers D-07, D-08, D-09, D-107, D-108, and D-109 will be calculated from the maximum dc output voltage, current limit amperes and efficiency using standard engineering formulas. The charger output power is governed by the charger loading and is not affected by input frequency. Since the charger load is > 50 kW, 2 kW will be added and the resulting value rounded up to the next higher full kW.

Security battery charger D-24 will also be in current limit, but certain details about this charger are considered safeguards information, and are not available for this calculation. The input kW during current limit is calculated from the input voltage and current, then scaled to match the current limitation caused by the upstream MCC breaker. The computation is similar to that used for motors (including adding 1 kW since the charger load is < 50 kW and rounding up to the next higher full kW), but without the frequency multiplier. Since power factor is not given, the kW is conservatively calculated as if the power factor was unity.

The charging pumps, which are fed via Variable Frequency Drives (VFDs), are another special case. The VFD controls output voltage and frequency, so pump speed and loading are not impacted by EDG output frequency. Therefore, the load multiplier for EDG frequency variation does not apply for these pumps. The loading is calculated from the drive input kVA and pf using the standard engineering formula, adding 2 kW (since the VFD load is > 50 kW), and rounding up to the next higher full kW.

Step 9 - Evaluation of EDG Load Management

The EDG loading provides the maximum load including the loads automatically supplied by the EDG and the manual loads added prior to entering the EDG load management procedures by plant operators. However, to support the design basis events (e.g.,LOCA, MSLB), there are several loads that must be capable of being supplied by the EDG to support plant operation . Plant operators must be capable of managing the load on the EDG to be able to cope with the event by removing and adding load from the EDG to maintain the EDG within its desired load rating.

Therefore, an evaluation is performed utilizing the load kW from Step 8 above to demonstrate that the plant operators are capable of managing the EDG load within its desired rating to support adding the necessary plant loads to support the design basis event. This includes the required loads to be manually loaded onto the EDG to support the transition from the injection phase to the recirculation phase of a LOCA event. The following is a discussion of the loads that are required to support the event based on emergency operating procedures and plant licensing basis:

Component Cooling Water (CCW) Pumps - The component cooling water pumps are required to support the removal of residual and sensible heat from the reactor coolant system, via the RHR heat exchangers during the recirculation phase of a LOCA to support long term cooling and remove heat from the RHR, SI and Containment Spray pump seal coolers to maintain the integrity of the pump seals. Therefore, the plant operators must have the capability to manually load a CCW pump on the accident unit prior to entering the recirculation phase of the event. The CCW pumps are not required to support a safety function prior to the recirculation phase of the LOCA. For a Main Steam Line Break (MSLB), seal water flow to the RCPs must be maintained in order to prevent a small break LOCA through the RCP seals. The required seal water flow can be provided via either the CCW pumps or the charging pumps. Therefore, the plant operators must have the capability to manually load either a CCW pump or a charging pump on the accident unit during an MSLB.

Charging Pumps - For a Main Steam Line Break (MSLB), seal water flow to the RCPs must be maintained in order to prevent a small break LOCA through the RCP seals. The required seal water flow can be provided via either the CCW pumps or the charging pumps. Therefore, the plant operators must have the capability to manually load either a CCW pump or a charging pump on the accident unit during an MSLB.

Battery Chargers - The station battery chargers are interlocked such that if a LOOP occurs they will disconnect from their 480V source until manually restored by plant operators. The safety related station batteries are sized to supply load to the DC system for a period of 1 hour. Therefore, the plant operators must have the capability to manually load the battery chargers that were aligned prior to the event after a LOOP to restore supply to the DC system from the battery chargers. Therefore, a maximum of 2 battery chargers per EDG are required to be restored to support the event. Swing charger D-09 can be aligned to replace either D-07 or D-08. Similarly, swing charger D-

109 can be aligned to replace either D-107 or D-108. Therefore, the two chargers per EDG consist of one of D-07, D-08, or D-09 and one of D-107, D-108, or D-109.

Miscellaneous Loads - All remaining loads the plant operators may manually load onto the EDG will be as EDG loading permits following the EDG Load Management Procedure. The above loads provide the required manual loads to support the event and are time critical in nature depending on the event. Therefore, no additional loads are required to be evaluated and plant operators will manage EDG loading as necessary.

All ECCS loads may be operating during the injection and recirculation phase for some period of time. The SI, RHR and CS pumps may all be loaded onto the EDG during the recirculation phase of a LOCA until conditions permit turning off the load (RCS pressure, containment pressure, or NaOH requirements). Therefore this calculation ensures that the EDG will be capable of carrying all ECCS loads in addition to the CCW pump to support the beginning of the recirculation mode of a LOCA.

ACCEPTANCE CRITERIA

The EDG steady state loading must be within the following ratings:

- EDGs G-01 and G-02 – 2850 kW for 2000 hours/year
- EDGs G-03 and G-04 – 2848 kW for 2000 hours/year and 2951 kW for 195 hours/year

These ratings can be used in combination provided that the total load hours do not exceed the overall EDG rating within the 30 day mission time for the EDGs. For example, 100 hours at a loading between the 200 and 2000 hour ratings is effectively worth 1000 hours of running at a value below the 2000 hour rating in terms of engine wear. This is to ensure that the EDGs are capable of supplying their licensing basis required loads as necessary to meet PBNP GDC 39.

Acceptance criteria for minimum steady state terminal voltage for 4.16 kV system loads supplied by EDGs: All safeguards motors fed from the 4.16 kV buses shall be maintained above their minimum allowable continuous running voltage at the terminals of the motors (90% of rated voltage. This ensures that the required 4.16 kV system safeguards motors are capable of performing their safety functions as required to meet PBNP GDC 39.

Acceptance criteria for minimum 480 V switchgear and MCC voltage: All 480 V switchgear and MCC bus voltages shall be maintained at or above 440 V. This value exceeds the highest (most conservative) voltage requirement for the 480 V switchgear and MCCs. It allows a margin of approximately 3.3 V above the limiting value of 436.7 V at MCC 1B-49, and margins of approximately 9 V above the most limiting 480 V switchgear and MCC voltages.

The extra voltage margin resulting from the 440 V acceptance value selected for this section is included to allow for additional voltage drop through the system cables and transformers resulting from loads that may be added by the operators under the guidance of AOP-22. As stated above, this results in required switchgear and MCC voltages higher than those used to determine the degraded grid setpoint. The resulting terminal voltage at the manually added loads will be higher than the terminal voltage where these loads are energized because no load shedding occurs. This ensures that the required 480 V system loads evaluated are capable of performing their safety functions as required to meet PBNP GDC 39.

Acceptance criteria for maximum allowable voltage setting for EDGs: All safety related motors shall be maintained below their maximum allowable continuous running voltage at the terminals of the motors (110% of rated voltage). All safety related battery chargers shall be maintained below 506 V (see assumption below). The secondary voltage under loaded conditions (rated kVA on the secondary side of the transformer shall not exceed 105%. This ensures that the required safeguards loads evaluated will be capable of performing their intended safety functions as required to meet PBNP GDC 39 without excessive heating or loss of service life due to over excitation.

Acceptance criteria for generator kW and kVA loading: The steady state loading on G-01, G-02, G-03 and G-04 shall be maintained within the machine rating of 3560 kVA down to a power factor of 0.8 (2848 kW and 2136 kVAR at minimum power factor). This ensures that the generator is capable of performing its intended safety function as required to meet PBNP GDC 39 without excessive heating.

ASSUMPTIONS

It is assumed that the Motor Operated Valves (MOVs) do not impact the EDG steady state loading.

Basis: The majority of MOVs in the system receive an automatic start signal to change position within the first minute of the accident. The total maximum load as a result of the MOVs will be no greater than approximately 30 HP. The MOVs will operate prior to the addition of any manual loads by the plant operators. Therefore, the operation of the MOVs will remain within the EDG capability since the 200 HP RHR pump would not be manually loaded on the shutdown unit until after the MOVs have actuated automatically. In addition, the plant operators may manually operate individual valves to support mitigation of the event, which will not impact the steady state loading of the EDG because they operate for a short duration (less than one minute) and are a relatively small load on the EDG. Therefore, the operation of MOVs on the EDG will not impact the EDG steady state loading analysis and are not considered part of the overall load. It should be noted that a number of MOVs are shown in the ETAP model as "ON" with 0% loading. These are the valves that would change position on an SI signal. The valves were modeled this way to make it easy to identify which valves change position automatically as a result of the event. The 0% loading ensures that these valves do not impact the EDG steady state loading analysis.

It is assumed that the maximum intake air temperature for G-03 and G-04 is 95 °F.

Basis: G-03 and G-04 draw their intake air directly from the outdoors via the louvered openings on the EDG building. The assumed maximum temperature of 95 °F is consistent with the licensing basis maximum outdoor air temperature for the Control Room Ventilation System as defined as defined in FSAR Section 9.8.1. This temperature is conservative based on the 0.4% dry bulb temperature of 89.7 °F for Manitowoc, Wisconsin in the hottest month of July. A temperature of 95 °F is chosen for the design basis cases for conservatism and to provide margin in the event that the peak daytime temperature increases slightly above 89.7 °F.

It is assumed that the maximum BHP values for the SW pumps when there are only 3 pumps in operation are:

Pump	BHP
P-032A	300
P-032B	287
P-032F	307
P-032C	302
P-032D	289
P-032E	305

Basis: A separate calculation determines the SW system flow for various configurations allowed during plant operations and provides the maximum flow to establish the minimum header pressure. However, this calculation provides a list of the minimum flows to safety related components for any SW configuration that will be achieved during a LOCA. These values represent the minimum flows to safety related components because they are determined with the maximum amount of diversionary flow present. If the diversionary flow decreases, the flow to these safety related components increases. Therefore, the most limiting sum of flows for essential equipment is 5185 gpm using the flow (gpm) values to the safety related components in the most limiting case Header 0 (Header 9a is not considered in the scenario because a Technical Specification 3.7.8 TSAC is entered as a result of the configuration). It should be noted that the flows in the table for the recirculation phase in the calculation total to a lower flow value, however the CC heat exchangers would be in operation for residual heat removal and the inclusion of this additional flow would result in a higher overall flow requirement than during the injection phase. The remainder of flow is comprised of flow to non-essential loads (e.g., turbine hall, various room coolers, and main Zurn strainer backwash). Zurn strainer backwash (SW-2911-BS and SW-2912-BS) is always maintained in operation. The flow to each strainer backwash at a frictional pressure drop of 73 psid is 512 gpm. However considering a frictional pressure drop of 36.5 psid (which is less than the worst-case predicted values), the flow through each strainer backwash was conservatively calculated to be 362 gpm.

Therefore, the approximate total minimum flow in the service water system would conservatively be 5909 gpm (5185 gpm + 362 gpm + 362 gpm).

Since the flow across each pump varies due to the individual pump characteristics, the minimum flow is expected to be proportioned across the pumps similarly to the proportions shown for 6 pump operation. The pump flow and associated BHP from the pump curves are tabulated below:

A train

Pump	GPM (6 Pump)	Fraction	GPM (3 Pump)	BHP (3 Pump)
P-032A	918	29.53%	1745	300
P-032B	1231.85	39.63%	2342	287
P-032F	958.54	30.84%	1822	307
	3108.39		5909	

B train

Pump	GPM (6 Pump)	Fraction	GPM (3 Pump)	BHP (3 Pump)
P-032C	860	26.20%	1548	.302
P-032D	1355.79	41.31%	2441	289
P-032E	1066.10	32.49%	1920	305
	3281.89		5909	

These values represent the worst case BHP expected for 3 pump SW system operation when supplied from a single EDG.

It is assumed that the maximum allowable voltage for battery chargers fed by the 480V system is 506 V.

Basis: Non-motor loads on the 480 V system have a rated voltage of 460V or 480V. The maximum utilization and service voltage in a nominal service voltage of 480V system is 508V. Therefore, the maximum allowable voltage for the battery chargers are conservatively limited to 506V based on 460V + 10%, which is bounded by (less than) 480V + 10%.

It is assumed that the RHR mini-flow recirculation flow is 200 gpm.

Basis: This value is based on ultrasonic flow measurements of 160 gpm to 165 gpm and the vendor reported sizing basis for the flow restricting orifice. The flow is rounded up to 200 gpm for additional conservatism since the BHP of the RHR pumps increases with flow.

It is assumed that the mission time for the EDGs following a design basis event is 30 days.

Basis: The duration of design basis accidents (e.g., LOCA) in FSAR Section 14 analyses extends to 30 days. The 30 day accident duration covers mitigation to a point where the accident unit is in a stable long term recovery condition. As a limiting condition, these accidents assume a concurrent loss of offsite power to both units during the event such that onsite emergency power sources (EDGs) are required to supply loads for the accident unit, as well as shutdown loads for the non-accident unit.

A loss of offsite power duration for these events is not specified in the FSAR. For conservatism in this calculation, the loss of offsite power duration will be assumed to be the same as the longest accident duration analyzed, although offsite power may be restored well before termination of the analyzed event.

Assuming a 30 day EDG mission time for accidents bounds loss of offsite power durations assumed for other design basis events, such as plant fires (up to 72 hours) and station blackout (up to 4 hours). The 30-day mission time exceeds the onsite fuel oil storage capacity credited in the Technical Specifications to support 7 days of EDG operation, after which fuel oil can be replenished from offsite sources (FSAR 8.8 and TS B3.8.3). The onsite fuel oil capacity does not necessarily bound EDG mission time because onsite capacity is just one of multiple fuel oil sources that can support EDG operation.

Therefore, for the purposes of this calculation, an EDG mission time of 30 days is conservatively assumed based on offsite power restoration occurring at the completion of the longest FSAR analyzed accidents. This assumption is used only to estimate the impact of the EDG loading for a design basis event on the normal engine overhaul maintenance intervals.

Unvalidated Assumptions - None

RESULTS AND CONCLUSIONS

EDG Steady State Loading

The EDG loading resulting from each of the cases was tabulated (see EC 13180 for tabulated results). As expected, the worst case loading for each EDG occurs when the EDG is carrying the load for both units with a LOCA/LOOP in one unit and a LOOP in the other unit. The bounding case for each EDG includes the automatic (sequenced) loads plus the manually added loads that are added prior to Plant Operators utilizing the EDG Load Management Procedure for the EDGs.

The results of the analysis show that the A-train EDGs will remain at or below the 2000 hour rating of the machine under the worst-case plant. The results of the analysis show that the B-train EDGs will remain at or below the 195 hour rating of the machine under the worst case configurations. The loading on the EDGs will be reduced as time from the initiation of the LOCA increases. It is expected that within the first 24 hours the operators are capable of managing the load on the EDG to a value within the 2000 hour rating of the machines. The EDG loading is reduced over time because the SI pumps can be turned off as the primary loop is depressurized, the containment spray pumps can be turned off because the RWST is empty with containment temperature and pressure recovering, the loading on the containment accident fans is reduced as containment pressure recovers, and the battery charger loading is reduced as the batteries return to full charge. These items will allow the operators to manage the load on the EDGs to a value within the 2000 hour rating of the machine within the first 24 hours following a design basis event. For up to the first 24 hours, the loading on the B-train EDGs may be above the 2000 hour rating but will be below the 200 hour rating of the machines.

During the 30 day mission time for a DBE, the A-train EDGs will use less than 36.0% of their integrated maintenance interval. The B-train EDGs will use approximately 47.1% of their integrated maintenance interval. This leaves at least 52.8% (rounding down) of the integrated maintenance interval available to allow for surveillance and preventive maintenance testing between the 18 month overhauls. Therefore, the loading on the EDGs is considered acceptable.

It should be noted that there are several unquantified conservatisms included in the EDG loading modeled in ETAP. These include:

- Several transformer loads are taken at connected load with no diversity.
- The battery room vent fans (W-85 and W-86) are modeled at their high speed rating (25 HP) rather than the low speed rating (12.5 HP) (the fans automatically drop to low speed following a LOOP).

- Static loads within the model are considered to have a demand of 122% and actual loading would be less under EDG normal allowable voltage (97.3% to 103.3%) conditions.
- The impact of frequency is conservatively rounded up to a 102% (approximately 60.4 Hz) increase in load within the analysis for ETAP and would be less since the maximum allowable frequency is 60.3 Hz, which corresponds to a 101.5% increase in load.

Generator kVA Capability Evaluation

The kW value associated with 3560 kVA at 0.8 power factor is 2848 kW, which closely matches the 2000 hour rating of the prime movers. Provided that the power factor remains above 0.8 (80%), the 2000 hour rating of the prime movers will be more limiting than the generator rating. At the 195 hour prime mover rating of 2951 kW, 3560 kVA corresponds to a power factor of 0.83. As with the 2000 hour rating, provided that the power factor remains above 0.83 (83%), the 195 hour rating of the prime mover will be more limiting than the generator rating. The generator output MVA and power factor are within the rated values for all scenarios.

A review of the automatic and manually added loads shows that the bulk of the loads have a power factor better than 0.83, and that those that do not tend to be very small loads. Given the power factor of the base load, it is obvious that shedding and adding the loads shown in the table to manage EDG load will result in a load power factor higher than 0.8 under all expected conditions when the load is approaching but below the 2000 hour rating of the prime mover, and higher than 0.83 under all conditions when the B-train EDGs are expected to be loaded to a value between the 2000 hour and 195 hour ratings of the prime mover. The power factor of the base load is below 0.8 for some of the very lightly loaded cases, but in these cases, the loading is so low that 3560 kVA rating of the generator will not be challenged.

Therefore, Acceptance Criteria is met for all expected loading conditions on G-01, G-02, G-03, and G-04.

Minimum and Maximum Allowable EDG Voltage Settings

The highest minimum voltage setting required to meet the acceptance criteria is 4,049 V. This value is below and therefore bounds the existing procedural minimum voltage setting of 4050 V. The maximum allowable voltage setting for the EDGs is limited by the EDG maximum rating of 105%, not the loads it serves since the safety related load voltages remain below their maximum rated voltages. The maximum allowable voltage setting is 105% of nominal, or 4,368 V. This value is above and therefore bounds the existing procedural maximum voltage setting of 4300 V.

Therefore, the equipment are maintained within the acceptable voltage range and Acceptance Criteria have been satisfied.

Load KW Values for EDG Load Management

The kW values for each load considered for EDG load management was tabulated. The load values are the expected worst case load values based on the appropriate design inputs. The actual loading on any given piece of plant equipment may be lower based on actual plant conditions during an event. When removing load, the actual kW recovered at the EDG may be lower than what is tabulated. Similarly, when adding load, the actual kW added may be lower than what is shown in the table. Monitoring and allowing for these differences is the responsibility of the operators when implementing the EDG load management procedures in AOP-22.

EDG Load Management Evaluation

The plant operators are required to manage the EDG kW loading to ensure the EDGs remain within their applicable rating. During a LOOP with or without a LOCA, there are several loads that must be capable of being supplied by the EDG to support plant operation which total approximately 362 kW. Since the total kW for these load exceeds the available margin on all of the EDGs it is obvious that in order to remain under the applicable rating for the EDGs, the plant operators must remove some load prior to adding all of the remaining CLB required loads to the EDGs. In addition, consideration was given to the reduction of SW brake horsepower based on the number of operating pumps during the event being considered.

The results indicate the plant operators will be capable of managing the load on the A-train EDGs and maintaining the loading within the 2000 hr rating of the A-train EDGs. The plant operators will be capable of managing the load on the B-train EDGs within the 195 hr rating for up to 24 hours, bringing the loading to a value within the 2000 hour rating in no more than 24 hours after the start of the event, and maintaining it within the 2000 hour rating of the B-train EDGs for the remainder of the event.

For a Main Steam Line Break (MSLB) concurrent with a dual unit LOOP, the automatic loading on the EDGs will be the same as or bounded by that of the LOOP/LOCA event previously evaluated. The release of steam will cause a containment high pressure signal, which will initiate an SI signal, and a containment high-high pressure signal, which will initiate containment spray. The additional cooling resulting from the steam release will cause a reactor trip due to low pressurizer level. Since the primary coolant loop is intact, RCS pressure stays above 700 psig. The SI pump will run at full load until shutoff head is reached, and then the load will be reduced to its recirculation flow value. The pressure will remain above the RHR pump's shutoff head (345ft, or 150 psi from the pump curves), so the load will be at the recirculation flow value throughout the event. A single CCW pump (203 kW) or charging pump (88 kW) must be manually started to restore RCP seal flow for this scenario.

The RHR mini-recirculation flow is assumed to be 200 gpm (see above). From the pump curves the corresponding motor loading is 84 BHP at 60 Hz. This gives a kW loading of 70.5, rounded up to 71 kW using the pump motor data that results in the smallest change in RHR kW loading. Subtracting this from the lowest accident unit value results in a reduction of 140 – 71 = 69 kW from the value used to calculate the automatic loading.

The A-train EDGs can accommodate either the charging pump OR the CCW pump (but not both) and remain within their 2000 hour rating for an MSLB. The B-train EDGs can accommodate a charging pump and remain within their 195 hour rating for an MSLB. Depending upon plant conditions and EDG loading, the B-train EDGs can accommodate a charging pump within their 195 hour rating. They may be able to accommodate a CCW pump and remain within their 195 hour rating, but that is not assured for the worst case conditions. Therefore, a limitation must be imposed that either one CCW pump or one Charging pump is required to be manually loaded onto the EDG to re-establish RCP seal cooling for events without a LOCA (e.g., MSLB in containment).

The loading evaluated in this calculation envelopes both the injection and recirculation phases of the event, and demonstrates that all four EDGs are applied at loading values that are within the applicable ratings of the machines for all phases of the event. The loading evaluated considers that each EDG is the only EDG available to support both units loading. If more than one EDG were to start, run and connect to the bus, the load could be managed between the EDGs, thus ensuring additional margin on each machine after the EDG load management procedure was entered. Therefore, the Acceptance Criteria has been satisfied.

V. MAXIMUM VOLTAGE ANALYSIS

V.1 PURPOSE AND SCOPE

The purpose of the maximum voltage analysis is to determine the maximum voltage at plant equipment fed from the AC electrical distribution system to assure that the equipment is within its maximum voltage rating under normal operating conditions with the highest system voltage. The plant electrical system alignments developed in Section II.2.02 are used to determine the maximum voltage at each piece of plant equipment evaluated. The maximum pre-fault source voltages discussed in Section II.2.03 will be used to determine the voltage for each bus to be evaluated for maximum voltage.

The scope of the maximum voltage analysis is to evaluate the maximum voltage at the following 13.8 kV, 4.16 kV and 480 V buses including their associated electrical equipment (motors, transformers, cables, etc.). Additional buses may be added in the future, if necessary. The following buses will be considered in the maximum voltage analysis:

H-01	1B-02	2B-30	B-65	PP-19	PP-54
H-02	1B-03	2B-31	B-66	PP-20	PP-55
H-03	1B-04	2B-32	B-71	PP-21	PP-56
H-05	2B-01	2B-39	B-81	PP-22	PP-58
H-06	2B-02	2B-40	PP-1	PP-23	PP-59
H-08	2B-03	2B-41	PP-2	PP-26	PP-63
H-09	2B-04	2B-42	PP-3	PP-28	PP-65
1A-01	B-07	2B-43	PP-4	PP-29	PP-67
1A-02	B-08	2B-49	PP-5	PP-30	PP-70
1A-03	B-09	B-21	PP-6	PP-31	PP-71
1A-04	B-507	B-22	PP-7	PP-32	PP-75
1A-05	1B-11	B-33	PP-8	PP-33	PP-76
1A-06	1B-30	B-43	PP-9	PP-34	PP-80
1A-07	1B-31	B-44	PP-10	PP-35	PP-81
2A-01	1B-32	B-45	PP-11	PP-36	PP-82
2A-02	1B-39	B-46	PP-12	PP-42	PP-83
2A-03	1B-40	B-47	PP-13	PP-43	
2A-04	1B-41	B-48	PP-14	PP-44	
2A-05	1B-42	B-51	PP-15	PP-45	
2A-06	1B-43	B-500	PP-16	PP-46	
2A-07	1B-49	B-501	PP-17	PP-47	
1B-01	2B-11	B-60	PP-18	PP-48	

The scope of this analysis does not include the evaluation of the maximum voltage at the secondary of transformers with secondary voltages below 480 V_{LL} or security transformers XL-21 and XL-22.

The scope of this analysis does not include evaluation of the maximum voltage of G-501 and the portions of the system it provides alternate power for (i.e., the TSC and G-05 auxiliaries), when they are fed from G-501.

V.2 METHODOLOGY

The methodology used in this calculation section is not described in the Current Licensing Basis (CLB) for PBNP.

The following steps develop the maximum voltage at plant equipment within the Point Beach Nuclear Plant AC Electrical Distribution System. The plant equipment evaluated includes cables, motors, transformers and miscellaneous loads (e.g. heaters, battery chargers, etc.).

V.2.01 DETERMINATION OF MAXIMUM SYSTEM VOLTAGES

The maximum system voltages are calculated by Section II of the calculation. The maximum system voltages utilized for the short circuit analysis to provide the maximum pre-fault system voltages also provide the worst-case maximum system voltages. The worst-case maximum system voltages are calculated utilizing Sections II.2.01, II.2.02, II.2.03, II.2.04, and II.2.05. The following is a summary of the steps used to determine the maximum voltage at plant equipment.

V.2.01.1 The AC electrical distribution system model in ETAP is developed in Calculation 2008-0025 (Reference VII.1.26). The ETAP AC electrical system model will be utilized to calculate the maximum 13.8kV through 480V system voltages. (See Section II.2.01)

V.2.01.2 The plant operating conditions were developed in Calculation 2008-0025 (Reference VII.1.26) and Section II.2.02 determined the worst-case plant conditions for each bus being evaluated. The maximum system voltage will be equivalent to the worst-case pre-fault voltages calculated for short circuit. The worst-case plant configurations will provide the same bounding cases for both short circuit and maximum voltage. The cases above provide the worst-case maximum source voltage with the minimum loading on the system. All additional cases are bounded by the plant conditions evaluated and therefore no additional plant operating conditions are required. (See Section II.2.02)

V.2.01.3 The analysis utilizes the maximum allowable source voltages (e.g. main generators, offsite power, gas turbine, etc.) to provide the worst-case system voltage. The minimum cable temperature is utilized which provides the worst-case minimum cable impedance providing the maximum voltage at the equipment. (See Sections II.2.03 and II.2.04)

V.2.01.4 The maximum voltage is calculated by utilizing the ETAP load flow analysis module (Reference VII.3.01) and the AC Electrical System Model developed in Calculation 2008-0025 (Reference VII.1.26) to calculate the steady state voltage at each bus within the 345 kV system through the 480 V system. The Newton Raphson iterative technique is used to calculate the bus voltages for each plant operating condition evaluated. A load flow study case and its associated options were developed in Calculation 2008-0025 (Reference VII.1.26) for each plant operating condition. The load flow study cases place the generating sources (Main Generators, Gas Turbine Generator, EDGs and the 345 kV system) at their maximum allowable voltage. (See Section II.2.05)

V.2.02 EVALUATION OF MAXIMUM VOLTAGE AT EQUIPMENT

A review of Calculation 2008-0025 (Reference VII.1.26) and the Master Input Calculations (References VII.1.03, VII.1.04, and VII.1.05) are performed for each 13.8 kV, 4160 V and 480 V bus to establish the nominal voltage ratings of the equipment connected to each bus. The maximum allowable voltage rating for each component will then be established based on manufacturer's data, plant specifications, and/or industry standards. The maximum calculated voltage at the bus will be compared against the maximum allowable voltage rating of each component type. The calculation conservatively compares the supply bus voltage against the equipment maximum voltage because the minimum loading demand factor calculated is based on the transformer loading (See Reference VII.1.26). The demand factor is then applied to all components supplied by the transformer. This provides the maximum voltage to each bus supplied in the system but may be non-conservative on an individual load basis. Therefore, the maximum voltage rating will be conservatively compared to the maximum calculated voltage for the bus. This will provide a conservative evaluation because it neglects voltage drop through the cable and ensures that a wide range of demand factor values for individual equipment is enveloped.

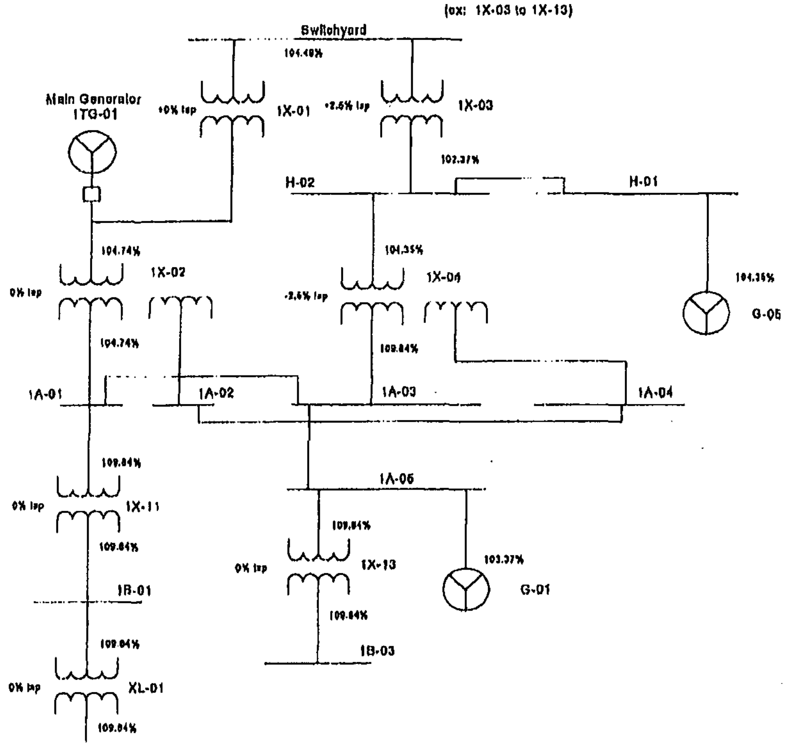
The maximum calculated worst-case voltage at each bus is determined by establishing the maximum voltage determined under all plant operating conditions analyzed. This will establish the worst-case maximum voltage to be used to evaluate maximum voltage conditions versus the maximum allowable equipment voltage. For each component type under consideration (e.g., cables, miscellaneous loads, motors, and transformers), the maximum voltage shown in any of the study cases will be compared against the appropriate Acceptance Criteria.

As stated above, the maximum calculated voltage under each plant operating condition is utilized to determine the transformer secondary terminal voltage under minimum loading conditions. The Acceptance Criteria V.3.03 value of 105% will be compared to transformer secondary terminal voltages calculated by ETAP. The light loading on the transformers will give higher (more conservative) voltages, and the transformers will be evaluated against the full load voltage criteria. The initial analysis conservatively considers the difference between the no-load and full load criteria as a step change from 110% at no load to 105% for any non-zero loading.

V.2.03 EVALUATION OF TRANSFORMER VOLTAGE DURING NO-LOAD CONDITIONS

The evaluation whether the maximum voltage of transformers will be acceptable during no-load conditions are based on the transformer tap configurations and the maximum allowable system source voltage. The figure below is a demonstration of how a particular set of transformer's taps and system source voltage are configured in the ETAP Model (Reference VII.1.26 and Input V.5.06):

Figure 1 - Transformer Tap Requirements for No-Load Condition
(ex: 1X-03 to 1X-13)



Note: All taps are on the primary side of the transformer (Reference VII.1.01).

V.2.03.1 Determination of Source Maximum Voltage

In order to evaluate maximum voltage at the transformers under no-load conditions, the source maximum voltage must be determined. From Figure 1 above, the possible maximum voltage sources for any transformer are the a) Switchyard, b) Gas Turbine Generator, c) Main Generator and/or d) Emergency Diesel Generator. The maximum voltage for each source is listed in Input V.5.06.

The EDGs are not connected to the system under transformer no-load conditions unless the generator is in isochronous mode (i.e., not paralleled with the system) as a result of a LOOP or outage testing. When in isochronous mode, the EDG is procedurally limited to 4300 V, or 103.37% of 4160 V (Reference VII.6.27 through VII.6.30)

V.2.03.2 Calculation of Maximum Secondary Voltage at Transformers Under No-Load Conditions

After the maximum source voltage is determined from Section V.2.03.1, the transformer maximum secondary voltage (in %) is calculated by dividing the maximum source voltage in percent of system nominal by the primary tap setting of the transformer in percent of the nominal primary voltage (e.g., 0% tap = 100%, -5% tap = 95%), multiplying by the ratio of the system nominal voltage to the transformer nominal primary voltage (this will be 1.00 in most cases, and will be left out of all but the first example unless it is not 1.00). This will be performed for each source to establish the worst-case transformer secondary voltage. It should be noted that the transformer secondary voltage is the same as the system nominal voltage in all cases. A multiplier of 100 is used to obtain the voltage in percent of nominal system voltage.

For example, if the maximum source voltage for the switchyard of 104.49% of 345 kV (Input V.5.06) is used as the source via transformer 1X-03 (see Figure 1 above), the voltage at the secondary of 1X-03 is calculated as $\left(\frac{104.49\%\ \text{Voltage}}{102.5\%\ \text{Tap}}\right)\left(\frac{345\ \text{kV}}{345\ \text{kV}}\right)100 = 101.94\%$ on the 13.8 kV system. Since the gas turbine generator can be run at 104.35% of 13.8 kV, the maximum no-load voltage for the 13.8kV system would be 104.35%. Therefore, the worst-case 13.8kV system voltage utilized would be 104.35%.

For transformer X-65, the primary is rated 13.2 kV, tapped at +5%, and connected to the 13.8 kV system. With a maximum source voltage of 104.35%, the transformer secondary voltage is:

$$\left(\frac{104.35\%\ \text{Voltage}}{105.0\%\ \text{Tap}}\right)\left(\frac{13.8\ \text{kV}}{13.2\ \text{kV}}\right)100 = 103.90\% \text{ of } 480\ \text{V}.$$

As can be seen from Figure 1 above, the source that provides the maximum transformer primary voltage is used for each transformer, for example, transformer 1X-11 can be fed from the main generator 1TG-01, the switchyard, or the gas turbine generator. The gas turbine generator (through the LVSAT 1X-04) provides the highest no-load primary voltage.

The no-load secondary voltage calculated as described above is then compared to the 110% of the transformer secondary voltage rating (Acceptance Criteria V.3.02) for no-load conditions.

V.3 ACCEPTANCE CRITERIA

V.3.01 Acceptance criteria for motor voltage: The terminal voltage at any 4160, 4000, 480, 460, or 440 VAC motor shall not exceed 110% of the motor's nominal voltage rating (References VII.2.07 and VII.2.08). For the safety related motors, meeting this ensures that the motors are within their equipment ratings and are capable of performing their intended safety functions as required to meet PBNP GDC 39 and FSAR Section 8.0 (References VII.8.04 and VII.8.26).

V.3.02 Acceptance criteria for transformers under no-load conditions: The secondary voltage under no-load (See Figure 1 in Section V.2.03) conditions shall not exceed 110% (References VII.2.12 and VII.2.17). This is to ensure that the safety related transformers are capable of performing their intended safety functions as required to meet PBNP GDC 39 and FSAR Section 8.0 (References VII.8.04 and VII.8.26).

V.3.03 Acceptance criteria for transformers under loaded conditions: The secondary voltage under full load (rated kVA on the secondary side of the transformer) shall not exceed 105% (References VII.2.12 and VII.2.17). This is to ensure that the safety related transformers are capable of performing their intended safety functions as required to meet PBNP GDC 39 and FSAR Section 8.0 (References VII.8.04 and VII.8.26). See Note in Section V.2.02.

V.3.04 Acceptance criteria for miscellaneous 480V system loads (e.g., heaters, control panels, power receptacles, battery chargers, Variable Frequency Drives (VFDs) other than for the charging pumps, which are addressed in V.3.06): The calculated voltage at the miscellaneous loads shall be less than 110% of the load's nominal voltage, or 506V for 460V or 480 V rated miscellaneous loads (Assumption V.4.01.1), or below 600 V for power receptacles (Assumption V.4.01.2). This is to ensure that the safety related miscellaneous loads are capable of performing their intended safety functions as required to meet PBNP GDC 39 and FSAR Section 8.0 (References VII.8.04 and VII.8.26).

V.3.05 Acceptance criteria for cables: The calculated ETAP maximum voltage for PBNP cables shall be less than the maximum cable voltage ratings of 25kV and 15kV (bus duct) for the 13.8kV system, 5kV for the 4.16kV system, and 1kV or 600V for the 480V system (References VII.1.04, VII.1.05, VII.4.34, VII.4.35, and VII.4.36). This is to ensure that the cables are capable of performing their intended safety functions as required to meet PBNP GDC 39 and FSAR Section 8.0 (References VII.8.04 and VII.8.26).

V.3.06 Acceptance criteria for charging pump VFDs: The terminal voltage at the VFDs for the charging pumps (1P-002A, 1P-002B, 1P-002C, 2P-002A, 2P-002B, and 2P-002C) shall be less than 514 V (Reference VII.4.41). This is to ensure that these non-safety related loads are capable of performing their design functions.

V.4 ASSUMPTIONS

V.4.01 VALIDATED ASSUMPTIONS

V.4.01.1 It is assumed that the maximum allowable voltage for Miscellaneous Loads fed by the 480V system (heaters, control panels, battery chargers, inverters, variable frequency drives, etc.) is 506 V.

Basis: Miscellaneous loads have a rated voltage of 460 V or 480 V per References VII.1.03 through VII.1.05. A review of Reference VII.2.03 states that the maximum utilization and service voltage in a nominal 480V system is 508 V. Therefore, the maximum allowable voltage for the miscellaneous loads are conservatively limited to 506V based on 460 V + 10%, which is bounded by (less than) 480 V + 10%.

V.4.01.2 It is assumed that the maximum allowable voltage for power receptacles installed at PBNP on the 480 V system is 600 V.

Basis: A review of the power receptacles installed shows that the majority are Crouse-Hinds or Russelstoll receptacles, all of which are rated 600 V (Reference VII.5.281, VII.5.282, and VII.5.283). Therefore, it is reasonable to assume that all power receptacles have a rating of 600 V consistent with the known ratings of the power receptacles installed at PBNP.

V.4.02 UNVALIDATED ASSUMPTIONS

None

V.7 RESULTS

The Maximum Voltage calculations were performed as described in Section V.6. The ETAP results appear in the summary table in Attachment E4. The full ETAP output reports are contained in Attachments F1, F3, F5, F7, F9, F19, F21, F23, F25, F27, F29 and F31.

V.7.01 Motor Maximum Voltage

Attachment E5 provides a comparison of the maximum calculated voltage versus the maximum allowable motor voltage. The following tables provide a summary of buses that supply motors for which the calculated maximum voltage is greater than the maximum allowable motor voltage. Therefore, Acceptance Criteria V.3.01 is not satisfied for motors (as rated below) supplied by these buses.

4000 V motors:

None.

460 V motors:

None.

440 V motors:

1B-01	2B-32	B-500
1B-32	2B-41	B-501
1B-41	2B-42	PP-03
1B-42	2B-43	PP-04
1B-43	B-22	PP-05
2B-01	B-43	PP-08
2B-31	B-66	PP-31

V.7.02 Transformer (Loaded) Maximum Voltage

Attachment E5 provides a comparison of the maximum calculated transformer secondary voltage versus the maximum allowable transformer secondary voltage. Acceptance Criteria V.3.03 was met for all transformers evaluated.

V.7.03 Transformer (No-Load) Maximum Voltage

The following table is a summary of the worst-case maximum calculated voltage at the transformer's secondary winding(s) as calculated in Section V.6.03. A review of the results show that for all transformers, the no-load secondary voltage is less than 110% and therefore Acceptance Criteria V.3.02 is satisfied. The calculated transformer secondary terminal voltages at No-Load conditions are as follows:

Transformer	Calculated Maximum Secondary Voltage (Max source, accounting for tap settings)	Acceptance Criteria V.3.02 for Transformer No-Load Conditions	Pass/Fail
1X-01	104.49%	110%	Pass
2X-01	104.49%	110%	Pass
1X-02	104.74%	110%	Pass
2X-02	104.74%	110%	Pass
1X-04	107.03%	110%	Pass
2X-04	107.03%	110%	Pass
1X-03	102.37%	110%	Pass
2X-03	102.37%	110%	Pass
1X-11	109.84%	110%	Pass
1X-12	109.84%	110%	Pass
1X-13	107.03%	110%	Pass
1X-14	107.03%	110%	Pass
2X-11	109.84%	110%	Pass
2X-12	109.84%	110%	Pass
2X-13	107.03%	110%	Pass
2X-14	107.03%	110%	Pass
1X-06	107.16%	110%	Pass
2X-06	107.16%	110%	Pass
X-07	109.84%	110%	Pass
X-08	104.35%	110%	Pass
X-27	104.35%	110%	Pass
X-48	104.35%	110%	Pass
X-65	103.90%	110%	Pass
X-66	103.90%	110%	Pass
X-72	103.90%	110%	Pass
X-500	104.35%	110%	Pass
X-704	109.84%	110%	Pass

V.7.04 Miscellaneous Load Maximum Voltage

Attachment E5 provides a comparison of the maximum calculated voltage versus the maximum allowable equipment voltage for miscellaneous loads. The following table is a summary of buses that supply miscellaneous loads for which the calculated maximum voltage is greater than the maximum allowable equipment voltage. Therefore, Acceptance Criteria V.3.04 are not satisfied for miscellaneous loads supplied by these buses as shown in Attachment E5.

Miscellaneous Loads:

None.

V.7.05 Cable Maximum Voltage

A review of the maximum voltage in each system from Attachment E4 shows that the maximum voltage on the 13.8 kV system is less than 14.2 kV, the maximum voltage on the 4.16 kV system is less than 4.5 kV and the maximum voltage on the 480 V system is less than 520 V. A comparison of the maximum calculated voltage for each system versus the maximum allowable cable voltage (see Input V.5.03) shows that the maximum calculated system voltages are less than the maximum allowable cable voltage. Therefore, the cables within the 13.8 kV, 4.16 kV and 480 V systems are within their voltage ratings and will meet Acceptance Criteria V.3.05.

V.7.06 Charging Pump VFD Maximum Voltage

Attachment E5 provides a comparison of the maximum calculated voltage versus the maximum allowable VFD voltage. The maximum calculated VFD terminal voltage is less than or equal to the maximum allowable voltage for the normal and alternate (buses B-08 and B-09) feeds for the charging pump VFDs. Therefore, Acceptance Criteria V.3.06 is satisfied for the charging pump VFDs.

V.8 CONCLUSIONS

This calculation section analyzes the maximum voltage on the 13.8 kV system to the current procedural limit of 14.4 kV (Reference VII.6.26). This value is above the 13.87 kV maximum voltage imposed in Limitation I.2.02.1. Therefore, the conclusions drawn in this section envelope and are not impacted by the restrictions in Limitation I.2.02.1.

The calculation performed the maximum voltage analysis for the equipment contained within the 13.8 kV through the 480V systems based on the worst-case plant operating conditions.

V.8.01 MOTOR MAXIMUM VOLTAGES

The maximum voltage at the buses supplying motors (i.e., the 4.16 kV and 480 V systems) were determined to ensure that all motors supplied by those systems are maintained at less than the maximum allowable motor voltage. The results of the calculation show that the following list of buses supply motors for which the calculated maximum voltage is greater than the maximum allowable motor voltage.

4000 V motors:

None.

460 V motors:

None.

440 V motors:

1B-01	2B-32	B-500
1B-32	2B-41	B-501
1B-41	2B-42	PP-03
1B-42	2B-43	PP-04
1B-43	B-22	PP-05
2B-01	B-43	PP-08
2B-31	B-66	PP-31

The maximum voltage applied to certain motors at these buses does not meet Acceptance Criteria V.3.01. During the periods when the voltage applied at the motors exceeds 110% of the motor's rated voltage, the motor will be overexcited and will run hotter than anticipated at full load in its rated ambient temperature. Under these conditions, motor service life may be reduced, however immediate failure is not expected. Running the motors less than fully loaded or at a lower ambient air temperature under these conditions will reduce the heating and reduce the impact of higher terminal voltage. PBNP performs motor condition evaluation (MCE) analysis per RMP 9387 (Reference VII.6.31) as periodic maintenance callups in PassPort (Reference VII.9) to trend the performance of the motor insulation on safety related motors. This will allow identifying degrading insulation performance prior to motor failure. AR01115746 has been initiated to document the condition that the subject motors powered from the buses listed above do not meet Acceptance Criteria V.3.01. Due to changing the X04 transformer taps to -2.5%, the terminal voltages for the safety related motors are reduced. The recommendations of AR01115746 remain bounding for this calculation.

V.8.02 TRANSFORMER MAXIMUM VOLTAGES

The maximum voltage at the transformers secondary terminals were determined to ensure transformers secondary voltage in the 13.8kV, 4.16kV and 480V systems are less than the maximum allowable voltage rating under no-load and full load conditions. The results of the calculation show that calculated transformer secondary voltages under no-load conditions (see Section V.7.03) were less than the maximum allowable voltage of 110% and Acceptance Criteria V.3.02 has been satisfied.

The results of the calculation show that all transformers have have a maximum calculated secondary voltage less than the maximum allowable voltage of 105% under loading conditions. The results for these transformers are acceptable.

V.8.03 MISCELLANEOUS LOAD MAXIMUM VOLTAGES

The maximum voltage at the buses supplying miscellaneous loads were determined to ensure all equipment supplied by the buses in the 480V system are maintained less than the maximum allowable equipment voltage. Acceptance criteria V.3.04 has been satisfied.

V.8.04 CABLE MAXIMUM VOLTAGES

The maximum system voltages (and consequently the cable maximum voltages) were determined to ensure all cables within the 13.8 kV, 4.16 kV and 480 V systems are maintained at less than the maximum allowable cable voltage. The results of the calculation show that the maximum calculated system voltages are less that the maximum allowable cable voltages. Acceptance Criteria V.3.05 has been satisfied.

V.8.05 Charging Pump VFD Maximum Voltage

The maximum voltage at the buses supplying normal and alternate power to the charging pump VFDs were determined to ensure that all of the charging pump VFDs are maintained at voltages within the allowable maximum. The results of the calculation show that the maximum calculated VFD terminal voltage is less than or equal to the maximum allowable voltage for all buses feeding the charging pump VFDs. Therefore, Acceptance Criteria V.3.06 has been satisfied.

EC 13180, Rev 1: EPU & Generator Breaker Mods Evaluated for Impact of Other Mods

1. Purpose

   The purpose of this engineering evaluation is to determine the impact of the proposed Extended Power Uprate (EPU) changes on the Point Beach AC Auxiliary System. The EPU changes to the AC electrical system include the uprate of major motors (steam generator feedwater pump motors and condensate pump motors), replacement of the generator step up transformer (X-01), upgrade of the generator isolated phase bus duct cooling, rewind and uprate of the main generator and addition of main generator circuit breakers. These changes were all evaluated during the summer of 2008 in calculations 2008-0025 and 2008-0026.

   These same calculations took into account the other major plant modifications that were intended to be installed prior to the power uprate modifications. The most significant modifications were the replacement of the 480V motor driven auxiliary feed pump motors (P-38A and P-38B) with new 4160V motor driven pumps, the completion of the four remaining charging pump variable frequency drive units and the installation of the main control room alternate source term modifications. Since the calculations for EPU were performed, the plans for the 4160V bus source for the new motor driven auxiliary feedwater pumps (1P-053 and 2P-053) and these other projects have changed slightly. These changes will be evaluated here to determine their impact on auxiliary power system performance in conjunction with the installation of the EPU changes.

2. Required actions:

   1. The charging pump variable frequency drive installation for 1P-2C should be completed before implementation of the AST and EPU modifications to regain margin.
   2. A detailed short circuit analysis must be performed to determine the short circuit duty for the breakers at Power Panel 4. If the breakers are shown to be applied above their interrupting ratings following the EPU change and auxiliary feedwater changes, these breakers must be replaced with higher rated breakers. Revision 0 of calculation 2004-0002 shows Power Panel 4 to be applied within its short circuit rating which reflects the present plant configuration. This is very similar to the configuration with the auxiliary feedwater pumps presently installed at the 480V buses. Therefore, it is likely, that the more detailed ETAP short circuit calculation revision will also show that this panel is applied within its rating.
   3. The protective overcurrent relays for the main feed breakers for buses 1B-03, 1B-04, 2B-03 and 2B-04 must be verified to allow the required loading without tripping the overload relay settings with the 460V auxiliary feedwater pump motor (P-38A) running during a LOCA in conjunction with the impact of not installing the VFD drive units for charging pumps 1P-2A, 2P-2A and 2P-2B.
   4. A formal revision to calculation 2004-0002 must be completed to verify the terminal voltages for the existing 460V motor driven auxiliary feedwater pumps when being used as emergency backups during a design basis LOCA event.
   5. The 4160V and 460V auxiliary pumps for each train of safety related equipment must be controlled such that both may not run simultaneously. Also, the 460V MDAFW motors must automatically trip on an SI signal, a degraded voltage trip or loss of voltage trip.

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3. Descriptions of changes since the EPU evaluations were performed:

The changes are described below for the major projects that have the potential to impact the already completed AC auxiliary system analysis performed for the EPU and generator breaker modifications contained in calculations 2008-0025 and 2008-0026. In attachment 1, a table is created that lists the recent changes to ongoing modifications versus the potentially impacted plant calculations prepared to reflect the plant design basis and for the EPU and generator breaker modifications. This table forms the road map for this evaluation.

3.1. Auxiliary Feedwater Modification changes (EC 1565, 1566 and 13401):

When the EPU auxiliary power system calculations were performed, the two existing 460V motor driven auxiliary feedwater (MDAFW) pumps and motors were to be replaced by two new 4160V motor driven auxiliary feedwater pumps and motors fed from the same safety related division as the existing motors (Bus 1A-05 and 2A-06) and physically located where the existing pumps and motors are presently installed. The Unit 1 MDAFW Pump was to be moved from 480V bus 1B-03 to 4160V bus 1A-05 and the Unit 2 MDAFW Pump was to be moved from 480V bus 2B-04 to 4160V bus 2A-06. The operation of the new pumps would be the same as the existing pumps.

Since this EPU AC auxiliary power calculation was performed, the scope of the auxiliary feedwater pump modification has changed as part of responses to questions by the US NRC during the license amendment request review. The planned approach now includes adding the two new 4160V motor driven pumps with the Unit 1 MDAFW pump (1P-053) fed from Bus 1A-06 and the Unit 2 MDAFW pump (2P-053) fed from bus 2A-05, along with keeping the two existing 460V motor driven pumps. The new 4160V pumps and motors would be located in the primary auxiliary building in the boric acid evaporator rooms. The new 4160V pumps and motors would fulfill the safety related functions for the various design basis accidents as originally planned. The new 4160V motors and pumps would now each be dedicated to one unit. The 1P-053 pump would be used for Unit 1 design basis events and the 2P-053 pump would be used for Unit 2 design basis events. The two existing 460V motor driven pumps would be used for startup, shutdown, certain non-accident events (SBO or Appendix R fire safe shutdown), and as manually operated backup auxiliary feedwater should a 4160V motor driven pump fail to operate. The relocation of the 4160V pump and motors results in an additional 150 feet of cable length for each motor from the 4160V bus to the motor terminal and is fed from the opposite safety train on each unit as compared to the existing 460V pumps.

The new 4160V MDAFW motors have been purchased as part of EC 1565 and 1566. The motor nameplate ratings are 350hp, 4160V, full load current 43A and locked rotor current 558% (240A) of full load current. The maximum running load will be the nameplate rating of 350HP.

In no case would a 4160V and 460V MDAFW pump be allowed to run simultaneously on the same safety related train of equipment.

3.2. Charging Pump Modification Installation Schedule Changes (EC 7372, 7375, 7376 and 7377):

The six charging pumps are being modified to add variable frequency drive units to convert the 60 cycle AC power for each motor to a variable frequency output to control the speed of the motor and pump. The existing motors are being uprated with new larger motors that would still supply the same maximum 100 break horsepower. At the time of the preparation of calculations 2008-0025 and 2008-0026, two of the charging pumps (1P-2B and 2P-2C) were installed with the remaining four VFDs (1P-2A, 1P-2C, 2P-2A and 2P-2B) scheduled to be installed prior to the first EPU and generator breaker outage for Unit 2 in the Fall of 2009. At this time, the installation may be delayed for the remaining four drives until 2011 which will be after the EPU and generator breaker modifications are installed.

3.3. Main Control Room Alternate Source Term modification changes (LAR 241):

When the EPU auxiliary power system calculations were performed, there were no changes planned to the AC auxiliary system that impacted the performance of the 480V or 4160V systems.

Since this EPU evaluation was performed, the scope of the alternate source term modification has changed as part of responses to questions by the US NRC during the license amendment request review. A revised amendment request was submitted in early December and now includes modifications to the common control room and primary auxiliary building ventilation systems and the Unit 2 façade freeze protection. The first change is during design basis accidents (LOCA) with a loss of offsite AC power, one train of control room ventilation must start automatically from the emergency diesel generator. This includes fans W-14A with W-13B1 or W-14B with W-13B2. Also, one primary auxiliary building ventilation exhaust filter fan (W-030A or W-030B) and one exhaust stack fan (W-021A or W-021B) must be manually started within 30 minutes under the control room's electrical management procedure guidance after the beginning of a design basis accident. This will occur by manual control room operator action after completing the injection phase of safety injection and during the recirculation phase with the main safety injection pumps (1P-015A, 1P-015B, 2P-015A and 2P-015B) secured. In order to accommodate the additional load on the "B" train emergency diesel generators (G-03 or G-04), the existing Unit 2 façade freeze protection circuits fed from MCC 2B-42 will be automatically shed during a loss of offsite power.

3.4. Main Generator rating after the EPU rewind

The main generator is planned to be rewound as part of the extended power uprate project. At the time of the preparation of calculations 2008-0025 and 2008-0026, the new maximum MVA rating was to be 713MVA. Based on recent input from Siemens, the rating after the rewind will be 684MVA with a 0.94 power factor with 75 psig of hydrogen pressure and a maximum of 85°F exciter cooling water.

3.5. 13.8kV Capacitor Bank Addition (EC 13600)

A modification has been created to add a new 3 phase capacitor bank to 13.8kV bus H-01. The new capacitor bank will have 5 stages of 3 MVAR each for a total capacitance of 15 MVAR. It will be connected to spare cubicle 15 at bus H-01. It will be used to support voltage for the 13.8 KV system for certain specific low offsite voltage scenarios when the G-05 gas turbine is not operating. Plant Operating procedures will prevent the CAP bank and G-05 from operating simultaneously.

3.6. Control room chiller modification to repower P-111A, PP-23 and HX-038B.

Several existing electrical loads will be reconnected to different power buses to allow relocation of the existing control room chiller HX-038B from a train B power source (MCC B-22 fed from 2B-02) to a train bus A power source (MCC B-33 fed from 2B-03). This provides greater capability to provide control room and cable spreading room cooling with a LOOP and a single failure.

This modification makes the following changes:

P-111A Cable Spreading Room chilled water pump – moving from 1B-31 (fed from 1B-03) to B43 (fed from 1B-04) with FLA 6.2 amps, 3-1/C-10 AWG, between 350 and 500 feet long, routed in conduit, tray and PAB penetration with current cable run from computer/mechanical room to MCC of 320 feet.

PP23 Warehouse 1 Power – moving from B33 (fed from 2B-03) to B43 (fed from 1B-04) with FLA 17.4 amps (from page 848 of 2004-0001), 3-1/C-2 AWG, ~520 feet long, routed in conduit and tray and current cable run from B33 to WH1 of 515 feet, B43 is ~2 feet away from B33.

HX-038B Control Room Compressor set – moving from B22 (fed from 2B-02) to B33 (fed from 2B-03) with FLA 98 amps (per dwg E-5 sheet 4B, 4 motors @ 23A each plus 6A static load), 3-1/C-1/0 AWG, between 100 and 500 feet long, routed in conduit, tray and PAB penetration with current run from computer/mechanical room to MCC of 254 feet. B22 is in the water treatment area, B33 is in the 26' PAB, directly above the RHR cubicles.

3.7. Battery room chiller addition

This modification adds a new chiller unit for the plant battery rooms that consists of 2 compressors with a total load of 125A and six fan motors of 3 hp each. These loads will be connected to 480V bus B08/B09 which is fed from the 13.8kV bus H-01.

3.8. Pump overhaul and reconditioning for service water pump (P-32F).

As part of a routine overhaul, the pump and impeller were re-conditioned for service water pump P-032F. The new pump was tested and the maximum running brake horsepower is 1.7 kW greater than the existing pump as modeled in the EDG loading section in calculation 2008-0026. Service water pump P-032F is fed from 480V bus 2B-03.

4. Evaluation of impact on available short circuit levels for AC auxiliary power systems buses from 480V to 345kV (Calculation 2004-0002 section II).

   The changes since the analysis in calculations 2008-0025 and 2008-0026 have an impact on the calculated available short circuit levels. Each of the changes will be evaluated individually and then the combined impact will be determined.

   4.1. Impact of auxiliary feedwater modification changes:

   4160V Motor Driven Feedwater Pumps

   The calculations performed for the generator breaker and EPU projects assumed that the new 4160V motor driven auxiliary feedwater pumps were installed in the existing location of the existing 460V motor driven pumps. The new electrical feeds were 1A-05 for the "A" train motor and 2A-06 for the "B" train motor. The present project scope for the motor driven auxiliary feedwater pumps is to install two new 4160V motors fed from 1A-06 and 2A-05 and the MDAFW pumps will be located in the PAB boric acid evaporator rooms instead of the existing auxiliary pump rooms. This adds an additional 150 feet of cable from the 4160V bus to the motor terminal and changes the power feed for Unit 1 from the A train to the B train bus and for Unit 2 from the B train to the A train bus. In addition, the existing 460V motor driven pumps will be retained and fed from their existing electrical sources of 1B-03 and 2B-04.

   The impact of the new location and 4160V bus source for the 4160V motors is to reduce the fault contribution for buses 1A-05 and 2A-06 and increase the fault contribution for buses 1A-06 and 2A-05. This impact can be evaluated by adding the full short circuit contribution of the 4160V motor to calculated available short circuit current at buses 1A-06 and 2A-05 and ignoring the reduction of fault current contribution for the original planned 4160V buses 1A-05 and 2A-06.

   The impact of the motors being moved is an increase of 240A (LRC) of short circuit current to buses 1A-06 and 2A-05. This is still within the short circuit ratings of each bus. The impact to the downstream 480V buses 1B-04 and 2B-03 is negligible since the 1X-14 and 2X-13 transformers limit the fault current and this is such a small portion of the fault current available at the 4160V buses 1A-06 and 2A-05.

   460V Motor Driven Auxiliary Feedwater Pumps

   The impact of retaining the 460V motor driven pumps is to add additional short circuit current when the motor driven pump is running. The existing motor driven pumps are kept for startup, shutdown and as a backup should the 4160V motor be unavailable. Calculation 2008-0026 does not include these 460V motors in the calculations for available short circuit current.

   To evaluate the impact of this difference, the results from calculation 2008-0026 for available short circuit current are increased to account for the 460V motor driven auxiliary feedwater pump's motor contribution. This increased level of short circuit current is compared to the breaker ratings for the bus and verified to be within the equipment capability.

   For example, auxiliary feedwater pump P-38A is fed from bus 1B-03. The existing 460V pump motor is rated at 250HP, 460V, 286A full load and subtransient reactance of 0.122 per unit (reference calculation 2001-0033, Rev 9). The short circuit current for this motor is 286A / 0.122 = 2344A. To simplify this impact, we just added the full motor short circuit contribution to the worst case calculated short circuit results for bus 1B-03 and the other motor control centers and power panels fed from 1B-03 (Attachment E1 and E2 of calculation 2008-0026). This new available value of short circuit current is then verified to be below the ratings of the associated circuit breakers. See section 4.9 for the compiled results for each motor.

   4.2. Impact of charging pump VFD installation delay for 1P-2A (1B-03), 1P-2C (1B-04), 2P-2A (2B-03) and 2P-2B (2B-03)

   The calculations performed for the generator breaker and EPU projects assumed that all six of the charging pumps would be replaced with variable frequency drives (VFD) that ultimately feed new charging pump motors. After the VFD is installed the charging pump motor can no longer contribute short circuit back to the source electrical bus for a fault on the system. At this time four of the six charging pump motors have not yet been replaced. These may not be installed until after the EPU and generator breaker are installed and placed into service.

The impact of the four motors not being replaced is higher available short circuit current will be available at the supply bus due to contribution from the existing motor, which is directly fed from the bus without a VFD. To evaluate the impact of this difference, the results from calculation 2008-0026 for available short circuit current are increased to account for the charging pump motor contribution. This increased level of short circuit current is compared to the breaker ratings for the bus and verified to be within the equipment capability.

For example, charging pump 1P-2A is fed from bus 1B-03. The existing charging pump motor is rated at 100HP, 460V, 134A full load and subtransient reactance of 0.229 per unit (reference calculation 2001-0033, Rev 9). The short circuit current for this motor is 134A / 0.229 = 585A. To simplify this impact, we just added the full motor short circuit contribution to the worst case calculated short circuit results for bus 1B-03 and the other motor control centers and power panels fed from 1B-03 (Attachment E1 and E2 of calculation 2008-0026). This new available value of short circuit current is then verified to be below the ratings of the associated circuit breakers. See section 4.9 for the compiled results for each motor.

4.3. Impact of alternate source term modification changes.

The changes for the alternate source term project involve changes to the loads when fed from the emergency diesel generators after a design basis accident with a concurrent loss of offsite power. These cases are much less severe than the cases already analyzed with offsite power available and these control room and PAB ventilation loads already modeled as running. The existing results for short circuit levels are not impacted by the recent AST project changes.

4.4. Impact of new main generator rating after rewind.

The main generator for unit 1 and 2 were modeled at the largest size being considered by the project in June 2008. This rating for the main generator use in the calculation is 713MVA. The latest data provided by Siemens is a rating of 684MVA. This value only impacts the available short circuit current from the machine. A smaller machine rating will reduce the contribution from the main generator to faults at the 19kV portion of the system and the downstream 4160V buses fed from X-02. The existing calculation is more conservative than the actual data and shows that the buses and breakers will be applied within their ratings.

The calculations have an open action item to verify the actual electrical parameters for the main generator once the final electrical design parameters are available. This action is still required to be completed as part of the project.

4.5. Impact of 13.8kV capacitor bank addition

The new capacitor bank will contribute short circuit current to bus H-01 during a fault. The capacitor bank will not be operated at the same time as the G-05 gas turbine generator. The existing analysis models the fault currents with G-05 ON in the limiting cases. The available fault current from the capacitor bank is less than the contribution from the G-05 generator and is of a much shorter duration. Thus the existing calculation bounds the case when the new capacitor bank is operating and the G-05 generator is OFF.

4.6. Impact of control room chiller modification to repower P-111A, PP-23 and HX-038B

The impact of the move of the three loads P-111A, PP-23 and HX-038B are listed below:

P-111A – Full load current of 6.2A with X"d of 0.206 (Ref master input calc 2003-0007) adds a short circuit current of 6.2A / 0.206 = 30A to bus B-43 and other buses fed from 1B-04.

PP-23 has two loads that contribute fault current. They are air conditioning units HX-303 and HX-304. HX-303 has a full load current of 11.2A with X"d of 0.256 (Ref master input calc 2003-0008) and adds a short circuit current of 11.2A / 0.256 = 44A to bus B-43 and other buses fed from 1B-04. HX-304 has a full load current of 6.2A with X"d of 0.275 (Ref master input calc 2003-0008) and adds a short circuit current of 6.2A / 0.275 = 23A to bus B-43 and other buses fed from 1B-04. This is a total net impact of 44A + 23A = 67A to bus B-43 and other buses fed from 1B-04.

HX-038B – has four motors each rated with full load current of 23A with X"d of 0.216 (Ref master input calc 2003-0007) and adds a short circuit current of 4 * (23A / 0.216) = 426A to bus B-33 and other buses fed from 2B-03.

4.7. Impact of battery room chiller addition

The new battery room chiller is being added to bus B08/B09 which is fed from 13.8kV bus H-01. This addition is a negligible impact to the available short circuit currents for the safety and non-safety buses downstream of transformers 1X-04 or 2X-04. The transformer impedance of X-04 will limit the short circuit contribution from these motors to buses A-05 and A-06. Therefore there is no impact to the safety buses. The impact on buses B08/B09 and downstream power panels is evaluated in the modification.

4.8. Impact of pump overhaul and reconditioning for service water pump (P-32F)

The change of the pump element has no impact on the motor short circuit contribution and thus no impact on the calculated short circuit calculations.

4.9. Compilation of short circuit differences on the impacted 480V buses

The combined impact for the short circuit currents as calculated in calculation 2008-0026 is tabulated below. The impact on 480V buses 1B-03, 1B-04, 2B-03 and 2B-04 is tabulated below, including the impact from the motor driven auxiliary feedwater pumps and the charging pumps that have not been installed with VFDs.

The data for the worst case available fault current for each 480V bus is taken from attachment E1 of calculation 2008-0026. The breaker ratings are taken from attachment E2 for the 480V motor control centers and power panels. The ratings for buses 1B-03, 1B-04, 2B-03 and 2B-04 are taken from the master input calculation (Calc 2001-0033).

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Bus	Max SC from calc (amps)	Impact of 460V MDAFW Pumps (amps)	Impact of Ctrl Room Chiller Mod	Impact of charging pumps (amps)	New max SC value (amps)	Breaker rating (amps)	Within rating?
1B-03	38,280	±2,344		±585	41,209	50,000	Yes
1B-31	16,762	±2,344		±585	19,691	25,000	Yes
1B-32	29,701	±2,344		±585	32,630	65,000	Yes
B-47	16,762	±2,344		±585	19,691	25,000	Yes
1B-30	1,237	±2,344		±585	4,166	65,000	Yes
PP42	16,762	±2,344		±585	19,691	35,000	Yes
1B-04	36,474		+97A	±585	37,156	50,000	Yes
B43	22,940		+97A	±585	23,622	25,000	Yes
1B-42	29,138		+97A	±585	29,820	65,000	Yes
2B-03	37,356		+426A	±1,170	38,952	50,000	Yes
2B-32	27,653		+426A	±1,170	29,249	65,000	Yes
2B-31	16,419		+426A	±1,170	18,015	25,000	Yes
B-33	24,441		+426A	±1,170	26,037	35,000	Yes
2B-30	1,292		+426A	±1,170	2,888	65,000	Yes
PP43	16,419		+426A	±1,170	18,015	35,000	Yes
2B-04	39,395	±2,344			41,739	50,000	Yes
2B-42	29,320	±2,344			31,664	65,000	Yes
B-21	27,843	±2,344			30187	65,000	Yes
PP 4	12,245	±2,344			**14,589**	**14,000**	**Potentially Exceeded**
PP 9	18,637	±2,344			20,981	25,000	Yes
PP 20	27,843	±2,344			30,187	35,000	Yes

The conclusion for the combined short circuit impact is that all buses with the exception of Power Panel 4 are applied within their short circuit rating. The quick conservative results of this evaluation show that available short circuit current at Power Panel 4 may exceed the short circuit rating of its breakers. This potential failure needs to be evaluated in more detail in the revision to calculations 2004-0001 and 2004-0002 that are to be completed as part of the detailed design for the EPU project. It is possible that the breakers at panel PP-4 may have to be replaced with breakers with higher interrupting ratings.

Revision 0 of calculation 2004-0002 shows Power Panel 4 to be applied within its short circuit rating which reflects the present plant configuration. This is very similar to the configuration with the auxiliary feedwater pumps presently installed at the 460V buses. Therefore, it is likely, that the more detailed ETAP short circuit calculation revision will also show that this panel is applied within its rating.

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5. Evaluation of impact on voltage drop for safety related buses 1(2)A-05 and 1(2)A-06. (Calculation 2004-0002 section III)

5.1. Impact of auxiliary feedwater modification changes:

4160V Motor Driven Auxiliary Feedwater Pump

Impact of moving the MDAFW Motors to Buses 1A-06 and 2A-05 along with the additional cable length to new 4160V motor driven pumps:

First, quantify the impact of additional cable length to new 4160V motor driven pumps when fed from 1A-05 and 2A-06:

The impact of the change for the 4160V motor driven auxiliary feedwater pumps (as already calculated) is the increased voltage drop to the motor terminal due to the increased cable length between the 4160V bus and the motor. For each motor, it is estimated that the increase in cable length is 150 feet. To allow for installation tolerance, this analysis uses an additional 200 feet of cable for each motor.

The cable lengths already used in calculation 2008-0025 and 2008-0026 are 200 feet of 3-1/C- #4/0 cable for the A train pump P-38E (called P-38A in the calc 2008-0026) and 880 feet of 3-1/C-#4/0 cable for the B train pump P-38F (called P-38B in the calc 2008-0026).

The most limiting motor terminal voltage for steady state running voltage and motor starting voltage were examined for each motor driven pump. The voltage drop from the 4160V bus to the motor was re-calculated using the new total cable length. This was done by taking the voltage drop from the bus to the motor and increasing it by the ratio of the new cable length divided by the original designed cable length.

Steady state voltage for A train pump from attachment G-01 of calculation 2008-0026:

Voltage at bus (1A-05) = 3923V

Voltage at motor terminal = 3921V

Voltage drop = 3923V – 3921V = 2 V

New voltage drop with longer cable = 2V * (200ft + 200ft)/200ft = 4 V

New motor terminal voltage – 3923V – 4V = 3919V which is above 90% of motor rated (3600V)

Motor starting voltage for A train pump from attachment G-09 of calculation 2008-0026:

Voltage at bus (1A-05) = 3841V

Voltage at motor terminal = 3835V

Voltage drop = 3841V – 3835V = 6 V

New voltage drop with longer cable = 6V * (200ft + 200ft)/200ft = 12 V

New motor terminal voltage = 3841V – 12V = 3829V which is above 80% of motor rated (3200V)

The voltage drop performance when the A train MDAFW pump motor is fed from 2A-05 instead of 1A-05 will be very similar to the calculated values above for 1A-05. This is valid since the loading and X-04 transformer impedances are nearly identical from Unit 1 to Unit 2. In addition, since the voltage is well above the acceptance criteria, any small error in the calculated voltage after the move will still be acceptable.

Steady state voltage for B train pump from attachment G-06 of calculation 2008-0026:

Voltage at bus (2A-06) = 3927V

Voltage at motor terminal = 3921V

Voltage drop = 3927V – 3921V = 6V

New voltage drop with longer cable = 6V * (200ft + 880ft)/ 880ft = 7.4 V

New motor terminal voltage = 3927V – 7.4V = 3919.6V which is above 90% of motor rated (3600V)

Motor starting voltage for B train pump from attachment G-21 of calculation 2008-0026:

Voltage at bus (2A-06) = 3840V

Voltage at motor terminal = 3815V

Voltage drop = 3840V – 3815V = 25V

New voltage drop with longer cable = 25V * (200ft + 880ft)/ 880ft = 30.7V

New motor terminal voltage = 3840V – 30.7V = 3809.3V which is above 80% of motor rated (3200V)

The voltage drop performance when the B train MDAFW pump motor is fed from 1A-06 instead of 2A-06 will be very similar to the calculated values above for 2A-06. This is valid since the loading and X-04 transformer impedances are nearly identical from Unit 2 to Unit 1. In addition, since the voltage is well above the acceptance criteria, any small error in the calculated voltage after the move will still be acceptable.

The impact of the additional cable length and the move from 1A-05 to 2A-05 and from 2A-06 to 1A-06 for the 4160V MDAFW pumps is acceptable

Impact of retaining the existing 460V motor driven pumps:

For the existing 460V motor driven pump, the recent calculation 2008-0026 has removed them from buses 1B-03 and 2B-04. These pumps are to become startup, shutdown and emergency backup auxiliary feedwater pumps. The electrical power configuration to these pumps is exactly the same as they exist in the plant today. The calculation of record for the existing configuration is calculation 2004-0002, revision 0. It shows that these motor driven pumps have adequate motor terminal voltage. The minor changes to the safety related portion of the AC system will not have a significant impact on these calculated results. However, a formal revision to calculation 2004-0002 must be completed to verify the voltages for these existing 460V motor driven pumps when being used as emergency backups during a design basis LOCA event.

5.2. Impact of charging pump VFD installation delay for 1P-2A, 1P-2C, 2P-2A and 2P-2B

The delay of the charging pump installation would leave the four remaining charging pumps in the present plant configuration. This configuration is already analyzed for the existing plant and is acceptable.

5.3. Impact of alternate source term modification changes.

The recently proposed changes for the alternate source term modification since calculation 2008-0026 was performed involve adding loads when fed from the onsite emergency diesel generators during a LOCA with concurrent loss of offsite power. This only impacts the cases with the emergency diesel generators providing power to the safety buses. The impacts for the EPU and generator breaker modifications all involve the auxiliary system when supplied from offsite power. In these calculations (2008-0025 and 2008-0026) for EPU and the generator breaker modification, the control room ventilation and primary auxiliary ventilation are analyzed as running in the existing analysis. The recently proposed AST modification changes do not impact this analysis and the results are valid without any adjustments.

5.4. Impact of new main generator rating after rewind.

The change to the main generator rating has no impact on the safety related electrical distribution system and no impact on the degraded grid relay set point.

5.5. Impact of 13.8kV capacitor bank addition

The new 13.8KV capacitor bank improves the voltage on the 13.8kV buses and downstream 4160V and 480V buses. Therefore the existing analysis without the capacitor bank installed is conservative.

5.6. Impact of control room chiller modification to repower P-111A, PP-23 and HX-038B

P-111A impact of move from 1B-31 (1B-03) to B-43 (1B-04)

Load is 5 hp, 460V, 6.2A full load (ref. Calc 2003-0007) – impact is 6.2A * 0.46kV * sqrt (3) = 5kVA

Power Panel 23 impact of move from B-33 (2B-03) to B-43 (1B-04)

Total load fed from PP23 as used in DBA cases fed from offsite power in calculation is 164kVA (ref. Calc 2004-0001) however the main feed breaker is 100A (PASSPORT for B52-333B) so the maximum load is 100A * 0.48kV * sqrt(3) = 83 kVA

HX-038B impact of move from B-22 (2B-02) to B-33 (2B-03)

Total chiller load is 78.1 kVA (ref. Calc 2003-0007)

These loads are moved to motor control centers B-33 and B-43 which are automatically shed (de-energized) during an "SI" or Loss of Voltage (Loss of Offsite Power , LOOP), therefore there is no impact to the previously calculated voltage drop to the safety loads during a design basis event by these changes.

5.7. Impact of battery room chiller addition

The new battery room chiller is added to bus B-08/B-09. This bus is fed from 13.8kV bus H-01. This small amount of load added to the 13.8kV system has a negligible impact on the calculated voltage for buses fed downstream of transformers 1X-04 or 2X-04. This change therefore has a negligible impact on the voltage at the safety buses as previously calculated during design basis events in calculation 2008-0026.

5.8. Impact of pump overhaul and reconditioning for service water pump (P-32F)

The pump overhaul very slightly changed the mechanical characteristics for the pump. As a result there is no measurable impact on the load or voltage drop during design basis accident conditions.

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6. Evaluation of impact on loading of safety related distribution equipment when fed from offsite power (Calculation 2004-0002 section III)

6.1. Impact of auxiliary feedwater modification changes:

The new motors are 350HP, 4160V, 43A full load operated at 350hp brake horsepower or less. This results in the following changes from the results in calculation 2008-0026.

Bus 1A-05 - decrease load by 4.16kV * 43A * sqrt(3) = 310 kVA

Bus 2A-06 - decrease load by 310 kVA

Bus 2A-05 - increase load by 310 kVA

Bus 1A-06 - increase load by 310 kVA

The combined impact of the load changes is compiled and evaluated below in section 6.9.

6.2. Impact of charging pump VFD installation delay for 1P-2A, 1P-2C, 2P-2A and 2P-2B

Calculation 2008-0026 evaluates the generator breaker and EPU modifications assuming the remaining four charging pumps have the new motors and variable frequency drives installed. The one B train charging pump (1P-2C) must be replaced before the EPU and AST modifications are implemented which reflects the already calculated configuration. For the A train charging pumps (1P-2A, 2P-2A and 2P-2B), the increased load for each charging pump is 17kW. This means that 1B-03 (1X-13 transformer) may see an additional 17kW of load and 2B-03 (2X-13 transformer) may see an additional 17kW *2 = 34kW of load.

The combined impact of the load changes is compiled and evaluated below in section 6.9.

6.3. Impact of alternate source term modification changes.

The changes for the alternate source term project involve changes to the loads when fed from the emergency diesel generators after a design basis accident with a concurrent loss of offsite power. These cases are much less severe than the cases already analyzed with offsite power available and the control room and PAB ventilation loads already modeled as running. The existing results for worst case electrical distribution equipment loading are not impacted by the recent AST project changes.

6.4. Impact of new main generator rating after rewind.

The change to the main generator rating has no impact on the electrical distribution equipment loading.

6.5. Impact of 13.8kV capacitor bank addition

The new 13.8kV capacitor bank is added to 13.8kV bus H-01. When operating, it will supply VARS to the auxiliary system which results in a net decrease in VARs being supplied from offsite power and thus reduced current being required from offsite transformers 1X-03 or 2X-03. It has no impact on the load being provided through transformers 1X-04 or 2X-04 or their downstream buses.

6.6. Impact of control room chiller modification to repower P-111A, PP-23 and HX-038B

P-111A impact of move from 1B-31 (1B-03) to B-43 (1B-04)

Load is 5 hp, 460V, 6.2A full load (ref. Calc 2003-0007) – impact is 6.2A * 0.46kV * sqrt (3) = 5kVA

Power Panel 23 impact of move from B-33 (2B-03) to B-43 (1B-04)

Total load fed from PP23 as used in DBA cases fed from offsite power in calculation is 164kVA (ref. Calc 2004-0001) however the main feed breaker is 100A (PASSPORT for B52-333B) so the maximum load is 100A * 0.48kV * sqrt(3) = 83 kVA

HX-038B impact of move from B-22 (2B-02) to B-33 (2B-03)

Total chiller load is 78.1 kVA (ref. Calc 2003-0007)

6.7. Impact of battery room chiller addition

The new battery room chiller is added to bus B-08/B-09. This bus is fed from 13.8kV bus H-01. This small amount of load added to the 13.8kV system has a negligible impact on the total load being supplied by transformer 1X-03 or 2X-03. It has no impact on any of the buses downstream of transformer 1X-04 or 2X-04. The impact on the 13800-480V transformer supplying bus B-08/B-09 is evaluated in the modification and does not impact the results of calculation 2008-0026.

6.8. Impact of pump overhaul and reconditioning for service water pump (P-32F)

The pump overhaul very slightly changed the mechanical characteristics for the pump. As a result there is no measurable impact on the load or voltage drop during design basis accident conditions.

7. Evaluation of impact on emergency diesel generator steady state loading (Calculation 2004-0002 Section IV)

The main generator breaker and EPU modifications do not change, add or remove loads from the safety related electrical buses for either unit. However, calculation 2008-0026 evaluated the impacts of the auxiliary feedwater modifications and other known changes and provides the technical basis for the EDG loading. This section will discuss how the recent changes in these other modifications impacts this EDG load evaluation.

7.1. Impact of auxiliary feedwater modification changes:

Existing calculation 2004-0002, revision 2 considers the loading on the emergency diesel generator with the new 4160V, 350hp motor driven feedwater pump motors installed. The move from 1A-05 to 2A-05 and from 2A-06 to 1A-06 still leaves one 4160V MDAFW pump on each train of emergency diesel generators (EDG). Since the existing analysis in calculation 2008-0026 models both train A buses on a single train A EDG and both train B buses on a single train B EDG, the load of the 4160V MDAFW is already correctly considered.

The decision to retain the existing 250hp motors fed from the 480V buses does not adversely impact the worst case load on the emergency diesel generators. One 4160V MDAFW and one 460V MDAFW pumps are fed from each safety division and procedural controls for the new and existing pumps will preclude running both pumps from one train at the same time. The existing analysis considers the larger 4160V pumps and therefore bounds the loading that would occur if the existing 460V motor driven pump is run instead of the new 4160V motor driven pump.

7.2. Impact of charging pump VFD installation delay for 1P-2A, 1P-2C, 2P-2A and 2P-2B

Calculation 2004-0004, Rev 2 evaluates the emergency diesel generator loading assuming the remaining four charging pumps have the new motors and variable frequency drives installed. The modifications for the generator breaker and EPU have no impact to the loads fed from the emergency diesel generators after a loss of offsite power.

The loading used for the new charging pumps is 90 KVA per pump in this calculation for a load of 100 brake horsepower at the pump. The original charging pumps are rated at 100 hp but are less efficient and thus require 107 KVA of load. This is determined from data in the calculation 2001-0033, revision 9. The original charging pumps have an efficiency of 77% and require 134A at 460V to develop 100 hp. This results in the load of 107 KVA (134A * 0.46kV * sqrt(3)).

7.3. Impact of alternate source term modification changes.

The loading for the emergency diesel generators after the changes for the AST modifications have already been evaluated and are repeated below from attachment 2:

EC 13180, Rev 1: EPU & Generator Breaker Mods Evaluated for Impact of Other Mods

Per Calculation 2004-0002, the EDG margins with automatic (sequenced) or manually added operator required loads are:

	Train A		*Train B*	
	G-01	*G-02*	*G-03*	*G-04*
Worst Case Load	*2,774 kW*	*2,773 kW*	*2,920 kW*	*2,917 kW*
2000 hr rating	*2,850 kW*	*2,850 kW*	*2,848 kW*	*2,848 kW*
195 hr rating	-	-	*2,951 kW*	*2,951 kW*
Margin 2000 hr rating	*76 kW*	*77 kW*	-	-
Margin 195 hr rating	-	-	*31 kW*	*34 kW*

The addition of 25 kW to Train B EDGs would significantly reduce the available margin and could be considered an adverse change. To recover margin, it has been proposed that controls be added so that the automatically loaded heat tracing transformer (X-17B) on Bus 1B42 would be stripped on a loss of power and would require operator action to restore power to transformer X-17B under EDG Load Management Procedures. Calculation 2004-0002 uses 35.6 kW (35% of 102 kW rated load) as the power requirement for the transformer X-17B (at breaker 1B52-429B). Thus, removal of the heat tracing as an automatic (sequenced) load would provide sufficient margin to allow the automatic loading of the CREFS fans.

In order to maintain the integrity of the reactor coolant pump seals, the control room operator must start either a component cooling water pump or a charging pump to provide cooling water flow to the RCP seals. The loading for the CCW pump (203 kW) is greater than the charging pump with VFD installed (88kW). The existing calculation for the A train emergency diesel generators uses one CCW pump. This is more severe that one charging pump including the impact of the original pumps which is an additional 17kW (for a total of 105kW) greater than the ones with VFDs. The B train diesel generators cannot support a CCW pump and only include one charging pump. For the calculated load on the B train EDG, we need to account for the additional 17kW of load for the original charging pumps.

	Train A		Train B	
	G-01	G-02	G-03	G-04
Worst Case Load	2,774 kW	2,773 kW	2,920 kW	2,917 kW
2000 hr rating	2,850 kW	2,850 kW	2,848 kW	2,848 kW
195 hr rating	-	-	2,951 kW	2,951 kW
Change for CREF loads	+ 25kW	+ 25 kW	+ 25 kW	+ 25 kW
Remove Façade Freeze (U2 B train)			- 35.6kW	- 35.6kW
Add power for original single Charging Pump (delta versus the ones already included with VFD)			+ 17 kW (if 1P-002C is not installed)	+ 17kW (if 1P-002C is not installed)
Additional load for SWP P-032F	+1.7 kW	+1.7 kW		
New worst case load	**2801 kW**	**2800 kW**	**2926.4 kW**	**2923.4 kW**
Margin 2000 hr rating	***49 kW***	***50 kW***	-	-
Margin 195 hr rating(with 1P-002C VFD not installed)	-	-	***24.6 kW***	***27.6 kW***
Margin 195 hr rating (With 1P-002C VFD installed)	-	-	***41.6 KW***	***44.6 KW***

This additional 17kVA per charging pump decreases the loading margin to the 195 hr rating on the B train diesel generators. Of the four remaining charging pumps to be installed with VFDs, three are fed from A train buses and one is fed from a B train bus. As a result, the B train charging pump (1P-2C) must be replaced with the variable frequency drive unit prior to the installation of the alternate source term modifications and the EPU modifications.

7.4. Impact of alternate source term modification changes.

EC 13180, Rev 1: EPU & Generator Breaker Mods Evaluated for Impact of Other Mods

The changes to the emergency diesel generator loading as a result of the recent changes to the alternate source term project have been evaluated as part of the recent revised license amendment for that project and therefore are not part of this evaluation.

7.5. Impact of new main generator rating after rewind.

The change to the main generator rating has no impact on the loading for the emergency diesel generators.

7.6. Impact of 13.8kV capacitor bank addition

The new 13.8kV capacitor bank is added to 13.8kV bus H-01 which is not fed from the EDG and therefore has no possible impact.

7.7. Impact of control room chiller modification to repower P-111A, PP-23 and HX-038B

These loads are not presently considered in the EDG loading since the buses they were fed from are automatically shed with an undervoltage condition during a loss of off site power. The buses where the loads are being moved to are also load shed and can be manually added back by the control room operator under the load management guidance in the operating procedures. Since these loads are not automatically loaded they will not be included in the EDG loading in calculation 2008-0026. This results in no change to the load requirements for the EDGs.

7.8. Impact of battery room chiller addition

The new battery room chiller is added to bus B-08/B-09. This bus is fed from 13.8kV bus H-01. Bus H-01 cannot be fed from the EDG and therefore has no possible impact.

7.9. Impact of pump overhaul and reconditioning for service water pump (P-32F)

The change of the mechanical pump element for Pump P-032F has a net possible impact of adding 1.7 kW when the pump is at run out. Thus it may add 1.7 kW to the A Train EDG.