UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION I
2100 RENAISSANCE BLVD., SUITE 100
KING OF PRUSSIA, PA 19406-2713

March 13, 2014

Mr. George H. Gellrich
Site Vice President
Calvert Cliffs Nuclear Power Plant
Constellation Energy Nuclear Group, LLC
1650 Calvert Cliffs Parkway
Lusby, Maryland 20657-4702

SUBJECT: CALVERT CLIFFS NUCLEAR POWER PLANT UNITS 1 AND 2 – NRC SPECIAL INSPECTION REPORT 05000317/2014008 AND 05000318/2014008

Dear Mr. Gellrich:

On January 31, 2014, the U.S. Nuclear Regulatory Commission (NRC) completed a Special Inspection Team (SIT) review of the January 21, 2014, dual-unit reactor trip at your Calvert Cliffs Nuclear Power Plant (CCNPP), Units 1 and 2. The SIT Charter (Attachment 1 of the enclosed report) provides the basis and additional details concerning the scope of the inspection. The enclosed report documents the inspection team's activities and observations conducted in accordance with the SIT Charter, which the team leader discussed on January 31, 2014, with you, and other members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with Commission rules and regulations and with conditions of your license. The team reviewed selected procedures and records and interviewed personnel. In particular, the inspection team reviewed event evaluations (including technical analyses), causal investigations, relevant performance history, and extent-of-condition reviews to assess the significance and potential consequences of issues, including security system response, related to the dual-unit trip which occurred during a severe winter weather event.

No findings were identified during this inspection. The team concluded that, overall, equipment functioned as designed, personnel acted to maintained plant safety and security in response to the severe weather event, and that CCNPP took appropriate actions to review and address the causes of the dual-unit trip. The enclosed chronology and list of documents reviewed (Attachments 2 and 3 of the enclosed report) provides additional details on the sequence of events that the team developed during the inspection.

Enclosure Attachment 4 contains Sensitive Unclassified Non-Safeguards Information. When separated from Enclosure Attachment 4, the enclosure and the transmittal document is decontrolled.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure (with the exception of Attachment 4 which contains security-related information), and your response (if any) will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Website at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

We appreciate your cooperation. Please contact Wayne Schmidt of the Division of Reactor Safety staff at (610) 337-5315 if you have any questions regarding this letter or the enclosed report.

Sincerely,

/RA/

Paul G. Krohn, Branch Chief
Engineering Branch 2
Division of Reactor Safety

Docket Nos: 50-317 and 50-318
License Nos: DPR-53 and DPR-69

Enclosure:
Inspection Report 05000317/2014008 and
05000318/2014008 w/Attachments 1, 2, 3, and 4

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T. Young, Director, Nuclear Security
T. Levering, Emergency Response Director
A. Lauland, Director, Homeland Security Advisor

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U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket Nos:	50-317 and 50-318
License Nos:	DPR-53 and DPR-69
Report Nos:	05000317/2014008 and 05000318/2014008
Licensee:	Constellation Energy Nuclear Group, LLC
Facility:	Calvert Cliffs Nuclear Power Plant, Units 1 and 2
Location:	Lusby, MD
Dates:	January 27 through 31, 2014
Inspectors:	Wayne L. Schmidt, Senior Reactor Analyst, Division of Reactor Safety (DRS) (Team Leader) Roy L. Fuhrmeister, Senior Reactor Inspector, Engineering Branch 3, DRS Jeff R. Bream, Physical Security Inspector, Plant Support Branch 1, DRS
Approved by:	Paul G. Krohn, Branch Chief Engineering Branch 2 Division of Reactor Safety

Enclosure

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SUMMARY OF FINDINGS

IR 05000317/2014008, 05000318/2014008; 01/27/2014 – 01/31/2014; Calvert Cliffs Nuclear Power Plant (CCNPP), Units 1 and 2; Special Inspection to review the January 21, 2014, Dual-Unit Reactor Trip; Inspection Procedure 93812, “Special Inspection.”

A three-person NRC team, comprised of regional inspectors and a regional senior reactor analyst conducted this Special Inspection, identifying no findings of significance. The NRC’s program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 4, dated December 2006.

REPORT DETAILS

1. Description of Events

In accordance with the Special Inspection Team (SIT) charter (Attachment 1), team members (the team) conducted a detailed review of the events leading up to, and equipment and operator response following, the January 21, 2014, dual-unit reactor trip (the event) at Constellation Energy Nuclear Group, LLC 's (CENG) Calvert Cliffs Nuclear Power Plant (CCNPP), Units 1 and 2. The team gathered information from the plant process computer (PPC) sequence of events (SOE) and alarm printouts and conducted interviews with plant operators and engineering staff to develop a detailed timeline of the event (Attachment 2). The following represents an abbreviated summary of the significant automatic plant responses and operator actions that began at approximately 9:25 pm on January 21, 2014, during a severe winter storm.

Initiating Event:

13.8 KV Service Bus 21 (Service Bus 21[1]) de-energized, because feeder circuit breaker (2104) opened on a phase-to-ground fault, due to snow/water intrusion into the weather resistant metal clad switchgear (See Section 4.b below). Service Bus 11 was unaffected. This resulted in:

- Unit 1 – Loss of power to 4 KV Safety Bus 14[2].
    - Safety Bus 11 remained energized and all reactor coolant pumps (RCP) remained running.
    - As designed, there was no immediate reactor protection system (RPS) actuation response.
    - Emergency diesel generator (EDG) 1B auto started to repower Bus 14, as designed, within associated time limits.
    - At about the same time that EDG 1B repowered Bus 14 – the vendor-supplied Mark VI digital turbine control system (Mark VI DTCS[3]) shutdown (See Section 4.b below). This resulted in the turbine control valves (TCV), turbine stop valves (TSV), and combined intercept valves (CIV) going closed, representing a turbine trip/loss of load without the normal dumping of electro-hydraulic control (EHC) hydraulic fluid pressure, which would have caused an anticipatory loss of turbine load RPS signal.

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[1] Service Bus/Busses will be used to denote 13KV busses fed from offsite power through one of the two Service Transformers, U-13000.

[2] Bus/Busses will be used to denote 4KV busses that are fed from a Service Bus through one of the six U-4000 Service Transformers.

[3] Unit 1 has had the Mark VI DTCS installed since 2006. Unit 2 has the initial Westinghouse analog turbine control system.

- Reactor pressure increased to the RPS high pressure setpoint resulting in an automatic trip and opening of the two primary power operated relief valves (PORV), as designed. The PORVs reclosed once the RPS high pressure signal cleared, as designed.
- Turbine bypass valves (TBV) and atmospheric dump valves (ADV) operated, as designed, to limit reactor coolant system (RCS) heat-up and pressure (Fast Open), and TBVs functioned to control RCS temperature.
- RPS also generated a turbine auto trip signal, which dumped the EHC pressure and the loss of turbine load RPS signal was received, as designed.
- Unit 1 turbine gland seal steam was lost and recovered by throttling open a manual pressure regulator bypass valve. Before the recovery, as expected when condenser vacuum lowered to about 22 inches of mercury vacuum (22" Hg) the TBVs went closed and operators shifted RCS temperature control to the ADVs. The gland seal recovery prevented loss of the running steam-driven feed pumps at about 20" Hg. TBVs again became functional as condenser vacuum recovered. (See Section 4.b below).
- EDG 1B was returned to a standby status after powering Bus 14 from Service Bus 11, its alternate source of offsite power.
- Hot Shutdown (Mode 3) was maintained with decay heat removed via TBVs and main feedwater.

- Unit 2 – Loss of power to Safety Bus 24, and Non-safety Busses 22, 23, 25, and 26.
    - Safety Bus 21 remained powered.
    - RCPs remained running, as opening the 2104 breaker isolated the fault to Service Bus 21.
    - RPS received an under-voltage (UV) trip signal and tripped the reactor (loss of power to RPS motor generator sets), as designed.
    - The turbine tripped on the auto trip signal from RPS.
    - TBVs and ADVs operated, as designed, to limit RCS heat-up and pressure (Fast Open).
    - Several non-safety loads lost power including the circulating water, condensate, condensate booster, and condenser air removal pumps, which caused condenser vacuum to lower.
    - EDG 2B auto started and repowered Bus 24, as designed, within associated time limits.
    - Operators controlled RCS temperature with the ADVs because the condenser was not available.
    - The 21 turbine-driven auxiliary feedwater (TDAFW) and 23 motor-driven auxiliary feedwater (MDAFW) pumps started automatically, as designed, on low steam generator (SG) water level and operated properly.
    - EDG 2B was returned to a standby status after powering Bus 24 from Service Bus 11, its alternate source of offsite power.

- Operators closed the main steam isolation valves (MSIV) after condenser vacuum continued to degrade and eventually went positive causing one of the low pressure turbine rupture discs to fail, as designed, to protect the condenser structure.
- Hot Shutdown (Mode 3) was maintained using the TDAFW pump and the ADVs to remove decay heat until the rupture disc was replaced, after which the TBVs and main feedwater were recovered to remove decay heat.

- Both Units - While evaluation of the cause and repairs were conducted to Service Bus 21, both units remained in a Hot Shutdown (Mode 3). Because Service Bus 21 was de-energized both units were in their applicable Technical Specification (TS) 3.8.1A Limiting Condition for Operation (LCO) action statement, because only one source of offsite power (Service Bus 11) was available to the safety busses on each unit. These LCOs were exited on January 25, when Service Bus 21 was reenergized and a normal electrical alignment reestablished, following repairs and testing.

2. Equipment Response to the Event

a. Inspection Scope

The team reviewed and assessed the initial equipment conditions and equipment response including consistency with the plant's design and regulatory requirements, and identification of any potential design deficiencies. The team reviewed the event timeline, Post-Trip Review (PTR) packages, operator logs, CENG corrective action program condition reports (CR), design requirements, modification packages, drawings, and component maintenance histories.

b. Findings/Observations

No findings were identified.

The team determined that given the initiating events, equipment at both units operated as designed to ensure the safety of the reactors. Further, CRs were properly initiated identifying equipment issues that required further evaluation.

The station electrical protection system functioned properly to de-energize and isolate Service Bus 21 when the phase-to-ground fault was identified. Both units responded as designed to the deenergization of Service Bus 21, considering the normal alignment of offsite power supplies to the safety and non-safety busses at both units.

Unit 1:

Based only upon the loss of power from Service Bus 21, Unit 1 should not have tripped. Bus 14 was repowered from its associated EDG 1B and all other safety-related and non-safety busses remained energized from their normal power supply Service Bus 11. However, the Mark VI DTCS did not function as expected, after one of its auctioneered power supplies was reenergized when EDG 1B repowered Bus 14. This unexpected action led to the closure of the TCVs, the TSVs, and the CIVs due to loss of power to valve controls, without generating a turbine trip signal, which resulted in a significant reduction of steam flow and a high reactor pressure. Within 6 seconds after the EDG 1B output breaker closed, the high pressure RPS signal opened the reactor trip breakers and tripped the turbine and both PORVs opened limiting the reactor pressure increase. The PORVs reclosed and the TBVs and ADVs automatically operated to control RCS temperature and pressure. The operators subsequently noted that a high pressurizer safety valve tail pipe temperature and quench tank conditions indicated a relatively small valve seat leak (See Section 4.b below). All other safety-related and risk significant equipment operated as designed.

Unit 2:

Unit 2 tripped as expected from the loss of power from Service Bus 21. Loss of power to the associated non-safety busses resulted in de-energizing the control rod motor generator set power supplies and non-safety balance of plant equipment which included loss of the circulating water, condensate, and condensate booster pumps. The RPS UV and turbine trip signals occurred properly. Bus 24 was repowered from its associated EDG 2B. The TBVs and ADVs automatically operated to control reactor temperature and pressure and auxiliary feedwater (AFW) actuated to provide feedwater to the SGs. The ADVs and TDAFW were used to control RCS pressure and temperature until the condenser was recovered as a heat sink, following replacement of a low pressure turbine rupture disc, which operated as designed to prevent damage to the condenser structure. All other safety-related and risk significant equipment operated as designed.

3. Event Diagnosis and Crew Performance

a. Inspection Scope

To evaluate whether the operators performed in accordance with procedures and training the team interviewed the operations crew that was on shift in the control room during with the January 21, 2014 dual-unit trip including: three senior reactor operators (SRO) - the shift manager (SM), the work control supervisor (WCS), the Unit 2 control room supervisor (CRS), the shift technical advisor (STA), and the three reactor operators (RO) - two assigned to Unit 2 and one to Unit 1. The team also reviewed narrative logs, PTRs, CRs, PPC trend data, and procedures implemented by the crew.

b. Findings/Observations

No findings were identified.

Unit 1:

The operators responded properly to the loss of power from Service Bus 21 and the complications caused by the failure of the Mark VI DTCS. The RO verified that RPS had not initially actuated, and no conditions calling for a reactor trip existed. Following the high reactor pressure trip, operators entered Emergency Operating Procedure - 0, “Post-Trip Immediate Action” (EOP-0) and completed all required actions, then transitioned to EOP-1, “Reactor Trip” (EOP-1).

Operators successfully restored gland sealing steam before complicating the event response with a low condenser vacuum trip of the running feedwater pumps. At the time of the event, gland seal steam was being supplied by reheat steam from the Unit 1 and Unit 2 turbines due to a known problem with main steam gland seal pressure regulator on Unit 1. When both turbines tripped, reheat steam was lost. Difficulties in starting an auxiliary boiler (due to a level instrument malfunction) resulted in a protracted loss of gland seal steam. The STA noticed decreasing vacuum and transfer of RCS temperature control to the ADVs when the TBVs closed as condenser vacuum decreased to 22” Hg, and advised the operators to restore gland seal steam. The operators restored gland sealing steam using the main steam pressure regulator bypass valve, recovering condenser vacuum and use of the TBVs, before the steam-driven feedwater pumps would have tripped at about 20” Hg.

Unit 2:

The operators responded properly to the loss of power from Service Bus 21. The WCS went to the control room when he heard the announcement of the trip, where he assumed the duties of STA for Unit 2. Operators entered EOP-0 and completed the immediate actions. The SM, CRS, and STA discussed whether to enter EOP-1 or EOP-2, “Loss of Offsite Power/Loss of Forced Circulation” (EOP-2). They subsequently determined that the entry conditions for EOP-2 were not met because the RCPs were still running. With the condenser unavailable as a heat sink, the operators controlled RCS temperature using the TDAFW and the ADVs.

Control room operators took prudent action to place EDG 2B in its standby condition when a possible lubricating oil leak was identified. Specifically, the equipment operator dispatched to monitor the operation of EDG 2B, upon entering the room, believed there may have been a lubricating oil leak, due to a low level alarm on the lubricating oil day tank and a haze in the room. The haze was subsequently determined to be due to exhaust gasses from engine start, dust, and wind-driven snow entering the room. Nonetheless, the control room operators conservatively transferred loads from EDG 2B, placing Bus 24 on Service Bus 11, its alternate offsite power source, in accordance with the applicable section of EOP Attachment 16, “500 KV Offsite Power Restoration.”

Following the rupture of the rupture disc on the #1 low pressure turbine, operators closed the MSIVs and during subsequent PTR evaluations noted that EOP-1 did not have procedural steps to ensure that the condenser was completely isolated if the circulating water, vacuum pumps, and gland sealing steam were lost. CENG took actions to add steps to EOP-1 for both units to address the closure of the MSIVs, if condenser vacuum was degrading and not immediately recoverable.

4. Effectiveness of Licensee's Response

a. Inspection Scope

The team reviewed and assessed the effectiveness of CENG's overall response to this event. The team interviewed plant personnel involved in the management and review of the event. The team also reviewed CRs generated, completed PTRs, Incident Review Team (IRT) reports, Operational Decision Making Instruction (ODMI) checklists, and Operability Determinations (OD). The IRTs included failure modes and effect analyses developed for the equipment challenges, causal analyses conducted, and interim and proposed longer term corrective actions. The team reviewed NRC and CENG generated operating experience searches to evaluate whether there were any potential precursors for which CENG should have taken action to prevent the dual-unit trip.

b. Findings/Observations

No findings were identified.

Overall, the team found that CENG responded properly to the event; adequately identified and reviewed potential adverse issues in CRs, PTRs and IRTs; and took suitable corrective actions prior to restart of both units. The IRTs identified the causes and developed corrective actions for the initiating events. The team did not identify any preexisting operating experience that could have caused CENG to have taken earlier actions to prevent the dual-unit trip or the loss of a security system (discussed in Attachment 4 which contains security-related information.)

Service Bus Water Intrusion:

The team found CENG's corrective actions adequate to reduce the potential for severe weather snow/water intrusion causing a future phase-to-ground fault on outdoor Service Busses. CR 2014-000569 and the associated IRT documented extensive and reasonable extent-of-condition and failure mode reviews. Corrective actions included installing external covers over susceptible ventilation openings on all Service Bus outdoor metal clad switchgear, as documented in CR 2014-000743. This installation was being tracked for removal at the conclusion of the winter season and reinstallation prior to the next winter. CENG actions for previous water intrusion events reasonably would not have prevented the snow intrusion into the Service Bus 21 switchgear cubicle.

Unit 1 Mark VI Digital Turbine Control System Failure:

While the exact cause for the Unit 1 Mark VI DTCS issue was yet to be identified, the team determined that CENG took adequate action to monitor the power supplies and make operators aware of the potential for a similar event prior to unit restart. CENG determined that the Mark VI DTCS central processor units (CPU) shutdown and reset at about the time the EDG 1B output breaker closed. CR 2014-000616 and the associated IRT documents the actions completed and planned. CENG used an ODMI checklist to document the monitoring of voltage and acknowledged that a similar momentary loss of power to Bus 14 or the downstream vital 120V AC bus (1Y10) could, in the future, cause a Mark VI DTCS response similar to that of January 21, 2014.

The Mark VI DTCS was supplied with two power supplies; one from an inverter, with safety-related DC and vital 120V AC feeds, ultimately from Bus 11 (the bus that was not lost) and the other from vital 120 V AC from Bus 14, (the bus that lost power and was repowered by EDG 1B). Within the Mark VI DTCS these power supplies are conditioned, rectified, and auctioneered through diodes before powering the actual CPUs. During troubleshooting CENG used vendor field service representative assistance. Testing included de-energizing the power feeds which resulted in normal power swapping within the system's internal power distribution.

At the time the inspection concluded, the cause of the CPU reboot had not been determined. CENG was still working with the system vendor to determine exactly what transpired within the Mark VI DTCS. CENG also contacted the vendor users group, as this system is used extensively in the electrical power generating industry, and had not received any feedback indicating that others users had seen this condition. Review of post-modification testing indicated that the system had responded properly to individual loss of the two power supplies following installation during 2006.

Unit 1 Pressurizer Safety Valve Seat Leakage:

Prior to Unit 1 restart, the team concluded that CENG documented an adequate operability basis for post-trip pressurizer safety relief valve 1RV-200 seat leakage. CENG used an ODMI checklist and an OD to evaluate any operability impact of the approximate 13 gallon per hour leak rate, including that the leakage could increase and potentially lower the valve's pressure setpoint or challenge the TS limit of RCS leakage. While in hot shutdown following satisfactory operation of both PORVs, Unit 1 operators identified and documented in CR 2014-000586 indications of PORV or pressurizer safety valve seat leakage (increased tail pipe temperature and quench tank pressure and temperature). Actions were taken to identify that 1RV-200 seat leakage was the likely source and reactor pressure was lowered to allow the valve to reach a lower temperature (as had been the practice a CCNPP). Upon re-pressurization the leakage had essentially stopped, however, the leakage returned several hours later. CENG planned to replace this valve and test it as part of the upcoming Unit 1 February 2014 refueling outage.

Loss of Security System:

The team concluded that the Security Department responded properly, as discussed in Attachment 4 (which contains security related information), taking appropriate and timely compensatory actions following the temporary loss of a security system. The team did not identify any design deficiencies. However, the team observed that Security Department documentation lacked detail on equipment recovery actions and important interactions between Security and Operations. The team determined that the security shift supervisor in conjunction with Operations appropriately assessed the plant conditions and concluded that the declaration of a security event was not appropriate, and that there was no condition that required entry into the Emergency Plan. The Security Department used CRs to document issues appropriately.

5. Risk Significance of the Event

a. Initial Assessment

The initial risk assessment for this event is documented in the enclosed SIT charter (Attachment 1).

b. Final Assessment

Using the information developed by the team, a Region I SRA, conducted a risk estimate of conditional core damage probability (CCDP) for each unit. This included reviewing the CCNPP Unit 1 and Unit 2 Standardized Plant Analysis Risk (SPAR) Models and making several changes: to better model power supplies to non-safety 4KV Busses; to address logic issues with once through cooling operations; and modeling issues with AFW flow controls. These changes lowered the baseline zero test and maintenance transient CCDP to the very low E-6 per year range.

Unit 1:

The final CCDP estimate remained in the low E-6 per year range, with less than a factor of two increase above the baseline zero test and maintenance transient CCDP. The assumptions made included that Bus 14 initially de-energized when Service Bus 21 de-energized, that both PORVs opened as a result of the Mark VI DTCS failure driven RCS pressure transient, and that the operators had a potential to fail to maintain condenser vacuum if gland sealing steam was not realigned properly. The dominate core damage sequence was a transient with a mechanical failure of RPS to shutdown the unit with the PORVs and SRVs remaining open.

Unit 2:

The final CCDP estimate remained in the low E-6 per year range, with less than a factor of two increase above the baseline zero test and maintenance transient CCDP. The assumptions made included that Service Bus 21 de-energized. The dominant core damage sequence was a transient with the loss of steam generator cooling due to failure of AFW and inability to successfully complete once through cooling.

6. Exit Meetings

On January 31, 2014, the team presented their overall assessment and observations to members of CENG's management led by Mr. G. Gellrich, Site Vice President, and other members of his staff. The inspectors confirmed that any proprietary information reviewed during the inspection period was returned to CENG.

ATTACHMENT 1 - SPECIAL INSPECTION TEAM CHARTER

SPECIAL INSPECTION TEAM CHARTER
Calvert Cliffs Nuclear Power Plant Unit 1 and Unit 2
Dual Reactor Trips due to the Loss of the Unit 2 '21' Service Bus
January 21, 2014

Background:

At 9:25 pm, on January 21, 2014, a dual-unit reactor trip occurred at the Calvert Cliffs Nuclear Power Plant. The feeder breaker to the '21'13.4KV Service Bus tripped, which resulted in a loss of the '21' Service Bus and a partial loss of offsite power to both units. The preliminary cause of the loss of the '21' Service Bus is the weather related impacts of ice and snow which caused a fault on the 21 buswork. A loss of the '21' Service Bus resulted in a loss of plant equipment including the Unit 2 motor generator sets for the control element drive mechanisms (CEDM), the Unit 2 circulating water pumps, the Unit 2 main feed water pumps, and some security equipment. The most likely cause of the trip for Unit 2 is the loss of the power to the CEDMs which caused the control element assemblies (CEA) to drop into the reactor core. The loss of the '21' Service Bus also caused a loss of 1 safety-related 4KV bus on both units, resulting in one safety-related emergency diesel generator (EDG) starting on each unit to supply power to its respective 4KV bus.

The loss of the '21' Service Bus should have resulted in a trip of only Unit 2. However, Unit 1 tripped on high pressurizer pressure. The preliminary cause of the Unit 1 trip is a malfunction of the Mark VI digital turbine control system. This resulted in a slow closure of the turbine control valves, a heat-up of the reactor coolant system, and finally a reactor trip on high pressurizer pressure. For Combustion Engineering technology plants, a high pressurizer pressure trip also opens the pressurizer power operated relief valves (PORV). A safety relief valve appears to have some leakage following PORV closure.

The loss of the '21' Service Bus also resulted in a partial loss of on-site power which resulted in the loss of some security equipment. It appears that appropriate compensatory action was taken.

The Unit 1 scram is considered uncomplicated, the Unit 2 scram would be considered complicated since the normal heat sink was lost and was not recoverable; however atmospheric dump valves functioned as designed. The NRC resident inspectors responded to the control room and are continuing to provide event follow-up.

Basis for the Formation of the SIT:

The Inspection Manual Chapter (IMC) 0309 review concluded that two of the deterministic criteria in Enclosure 1 of IMC 0309 were met due the unexpected system interaction which occurred resulting in both units tripping following a fault on a single, non-vital bus, and potentially repetitive failures of the 13.4 KV bus switchgear housing to protect the equipment from weather related events. A deterministic criterion in Enclosure 2 of IMC 0309 was also met due to the unexpected loss of a security system during the event.

ATTACHMENT 1 - SPECIAL INSPECTION TEAM CHARTER

The event was also evaluated for risk significance because the IMC 0309 review concluded that at least one deterministic criterion was met. Based upon the best available information, the Region I Senior Reactor Analyst (SRA) conducted a preliminary conditional core damage probability (CCDP) estimate for the Unit 1 and 2 events using the appropriate NRC SPAR models. The CCDP for Unit 1 was estimated to be in the low E-6 range and the CCDP for Unit 2 was also estimated to be in the low E-6 range. The dominant core damage sequences for the transient on Unit 1 involved a failure to control auxiliary feedwater and a loss of condenser vacuum. The event was somewhat more risk significant on Unit 2 due to the loss of the normal heat sink, since the Unit 2 Circulating Water Pumps are powered from the faulted bus. The dominant core damage sequence for Unit 2 included the loss of the main condenser heat sink with the failures of auxiliary feedwater and once through primary cooling (feed and bleed).

On January 22 and 23, 2014, the SRA discussed these results with the Constellation PRA staff and determined that the risk estimates (CCDP) performed by Constellation closely compared to the NRC SPAR model generated values.

Based upon the preliminary CCDP estimates, and in accordance with IMC 0309, the event falls within the overlap ranges of “No Additional Inspection” and “Special Inspection Team (SIT)” for Unit 1 and 2. After consultation with NRC management, an SIT was initiated.

<u>Objectives of the Special Inspection</u>:

The SIT will review Constellation’s organizational and operator response to the event, equipment and design deficiencies, and the causes for the event and subsequent issues. The team will collect data, as necessary, to refine the existing risk analysis. Additionally, the team leader will review lessons learned identified during this special inspection and, if appropriate, prepare a feedback form on recommendations for revising Reactor Oversight Process (ROP) baseline inspection procedures.

To accomplish these objectives, the team will:

1. Develop a complete sequence of events including follow-up actions taken by Constellation.

2. Review and assess the equipment response to the event. This assessment should include an evaluation of the consistency of the equipment response with the plant’s design and regulatory requirements, and potential design deficiencies. In addition, review and assess the adequacy of any operability assessments, extent-of-condition reviews, digital control system response, corrective and preventive maintenance, and post maintenance testing.

3. Review and assess the appropriateness and timeliness of compensatory actions put in place for the loss of a security system during the event and any potential design deficiencies.

ATTACHMENT 1 - SPECIAL INSPECTION TEAM CHARTER

4. Review and assess operator performance including procedures, logs, communications (internal and external), and emergency plan implementation.

5. Review and assess the effectiveness of Constellation's response to this event. This includes overall organizational response, failure modes and effect analyses developed for the equipment challenges, causal analyses conducted, and interim and proposed longer term corrective actions.

6. Evaluate Constellation's application of pertinent industry operating experience and evaluation of potential precursors, including the effectiveness of any actions taken in response to the operating experience or precursors; and

7. Collect any data necessary to refine the existing risk analysis and document the final risk analysis in the SIT report.

Guidance:

Inspection Procedure 93812, "Special Inspection," provides additional guidance to be used by the Special Inspection Team. Team duties will be as described in Inspection Procedure 93812. The inspection should emphasize fact-finding in its review of the circumstances surrounding the event. It is not the responsibility of the team to examine the regulatory process. Safety concerns identified that are not directly related to the event should be reported to the Region I office for appropriate action.

The Team will conduct an entrance meeting and begin the inspection on January 27, 2014. While on site, the Team Leader will provide daily briefings to Region I management, who will coordinate with the Office of Nuclear Reactor Regulation, to ensure that all other parties are kept informed. A report documenting the results of the inspection will be issued within 45 days following the final exit meeting for the inspection.

This Charter may be modified should the team develop significant new information that warrants review.

ATTACHMENT 2 – DETAILED SEQUENCE OF EVENTS

DETAILED SEQUENCE OF EVENTS		
The sequence of events was constructed by the team from review of Control Room Narrative Logs, corrective action program condition reports, post transient review reports, process plant computer (PPC) data (alarm message file and plant parameter graphs) and plant personnel interviews.		
	Unit 1	Unit 2
	Offsite Power Lineup: - Normal - all 500 KV Ring bus breakers closed 5051, 5072 and 5052 high lines in-service	
January 21, 2014	Initial Plant Conditions: 100% reactor power nearing end of core life. Electrical Lineup - Normal • 13KV Service Bus 11 supplying - Safety Bus 11 and Non-safety busses 12 and13 • 13KV Service Bus 21 supplying - Safety Bus14 Running Equipment - Normal • Reactor Coolant Pumps 11A/B and 12A/B (4/4) • Charging pump 12 (1/2) • CCW pump 12 (1/2) • Salt Water pumps 11 and 12 (2/3) • Service water pumps 11 and 12 (2/3) • Circulating water pumps 11 – 16 (6/6) • Steam-Driven Feed pumps 11 and 12 (2/2) • Condensate Pumps 11 – 13 (3/3) • Condensate Booster pumps 11 and 12 (2/3) Standby Equipment - Normal • TDAFW pumps: 11 in auto; 12 in standby (Trip throttle valve closed) • MDAFW pump 13 in auto	Initial Plant Conditions: 99.5% reactor power Electrical Lineup – Normal • 13KV Service Bus 21 supplying - Safety Bus 24 and Non-safety busses 22 and 23 • 13KV Service Bus 11 supplying – Safety Bus 21 Running Equipment - Normal • Reactor Coolant Pumps 21A/B and 22A/B (4/4) • Charging pump 21 (1/2) • CCW pump 21 (1/2) • Salt Water pumps 21 and 22 (2/3) • Service water pumps 21 and 22 (2/3) • Circulating water pumps 21 – 26 (6/6) • Steam-Driven Feed pumps 21 and 22 (2/2) • Condensate Pumps 21 – 22 (2/3) • Condensate Booster pumps 21 and 23 (2/3) Standby Equipment - Normal • TDAFW pumps: 21 in auto; 22 in standby (Trip throttle valve closed) • MDAFW pump 23 in auto
21:25:24	Service Bus 21 Feeder Breaker 252-2104 Opens	
	Bus 14 and 120 Vital AC 1Y10 De-energized	Bus 24 and 120 Vital AC 2Y10 De-energized
21:25:26	Bus 14 UV ESFAS	Bus 24 UV ESFAS
	Bus 14 Feeder Breaker 152-1414 Open	EDG 2B Start Signal
		Bus 24 Feeder Breaker 152-2401 Open
21:25:27		RX Trip Bus Undervoltage (RPS to Turbine Trip)
		Turbine Auto Stop Trip Solenoid Energized
		Turbine Loss of Load A-D Actuate (RPS)
		Reactor Trip Circuit Breakers 1-8 Open (RPS)
		Auto Stop Fluid Low Pressure
21:25:29		EDG 2B Start Signal
21:25:31-32		Bus 24 breakers open
21:25:33	EDG 1B at Speed	EDG 2B at Speed

ATTACHMENT 2 – DETAILED SEQUENCE OF EVENTS

21:25:34	EDG 1B breaker 152-1403 Closed - Bus 14 and 120 Vital AC 1Y10 Re-energized	EDG 2B breaker 152-2403 -Closed - Bus 24 and 120 Vital AC 2Y10 Re-energized
	Bus 14 Shutdown Sequencer Actuated	Bus 24 Shutdown Sequencer Actuated (21:25:36 by alarm typer)
21:25:40	High Pressurizer Pressure (A-D) actuated (RPS and PORV open)	
	Both PORVs Open (RV 402 and 404)	
	PZR relief valve indicates open from Acoustic Monitor (RV-202)	
	Reactor Trip Circuit Breakers 1-8 Open (RPS)	
	RX Trip Bus Under-voltage (RPS to Turbine Trip)	
21:25:42	Both PORVs Close (RV 402 and 404)	
21:25:55		Generator Trip 500 KV breakers 63 and 61 Open
21:25:57	Generator Trip 500 KV breakers 22 and 23 Open	

ATTACHMENT 3 – SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Interviews Conducted:

Dual-Unit Trip:
George Gellrich – Site Vice President
Amy Cordner – Unit 1 Mark VI Turbine Control IRT lead
Chris Jackson – Unit 2 13.8 KV Bus 21 phase-to-ground fault IRT lead
Brett Boucher – Unit 1 system engineer – Main Turbine
Kent Mills – Operations Contact – Shift Manager
Robert Henderson – Unit 2 Control Room Operator
Keith King – Work Control Supervisor (licensed Senior Reactor Operator)
Andrew McNeil – Unit 2 Control Room Supervisor
Jesse Mitchell – Shift Technical Advisor
Stephen Barger – Unit 2 Reactor Operator
Scott Kittler – Unit 1 Reactor Operator
Brian Hayden - Shift Manager at the time of the event

Security Issues:
Tuane Young, Director, Nuclear Security
Bob Pumphrey, General Supervisor Security Operations
Joe Wiggins, Electrical Maintenance Supervisor
Steve Loeper, Diesel System Engineer
Chris Coleman, I&C Technician / Security Maintenance

LIST OF DOCUMENTS REVIEWED

In addition to the documents identified in the body of this report, the inspectors reviewed the following documents and records.

Procedures:
Unit 1 Emergency Operating Procedure (EOP)-0 “Post-Trip Immediate Action,” Revision 10
Unit 2 EOP-0, “Post-Trip Immediate Action,” Revision 11
Unit 1 EOP -1 “Reactor Trip,” Revision 14
Unit 2 EOP -1 “Reactor Trip,” Revision 13
Unit 2 EOP Attachment 16, “500 KV Offsite Power Restoration,” Revision 17
CENG Fleet Administrative Procedure CNG-OP-1.01-1006, “Post-Trip Review,” Revision 00200

ATTACHMENT 3 – SUPPLEMENTAL INFORMATION

Drawings:
UFSAR Figure 8-1, "Electrical Main Single Line Diagram," Revision 44
63097SH0059, NSF Security System SDG Building Single Line Diagram, Revision 1

Miscellaneous:
Unit 1 Post Trip Review following January 21, 2014 trip, completed 1/24/2014
Unit 2 Post Trip Review following January 21, 2014 trip, completed 1/24/2014
Shift Turnover Information Sheet, dated January 21, 2014

Security Information:
SS-110, "Perimeter Intrusion Detection Probability Test Form," 1/23/14
CAS Activity Log, 1/21/14 – 1/26/14
Calvert Cliffs Nuclear Power Plant Security Plan, Training and Qualification Plan, Safeguards Contingency Plan, and Independent Spent Fuel Storage Installation Security Program, Revision 8
Safeguards Contingency Plan Implementation Procedure, Revision 9
SS-59, "Compensatory Measures," Revision 15
SS-101, "Post-Maintenance Testing of Security Equipment," Revision 4
SS-100, "Conduct of Security Equipment Maintenance and Modifications," Revision 10
SS-110, "Perimeter Intrusion Detection Probability Testing," Revision 7
CNG-CA-1.01-1000, "Corrective Action Program," Revision 00902
CNG-MN-4.01-1001, "Work Order Execution and Closure Process," Revision 00401
CNG-MN-4.01-1002, "Work Order Initiation, Screening and Prioritization," Revision 00500
CNG-MN-4.01-1003, "Work Order Planning," Revision 00701

Work Orders:
C92109008
C92046323
C92545238
C92545811
C92433629
C92229031
C92520288
C92479478
C92524661
C92145138
C92145131

ATTACHMENT 3 – SUPPLEMENTAL INFORMATION

Condition Reports:

2013-000255
2013-010114
2014-000572
2014-000586
2014-000597
2014-000606
2014-000616
2014-000626
2014-000631
2014-000646
2014-000678
2014-000700
2014-000713
2014-000717
2014-000727
2014-000729
2014-000808
2014-000811
2014-000816*
2014-000819
2014-000847*
2014-000895*
2014-000900*
2014-000901*
2014-000913*
2014-000940*
2014-000949*
2014-000950*
2014-000959*
2014-008921

* designates CRs generated based on NRC identified issues

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

None.

ATTACHMENT 3 – SUPPLEMENTAL INFORMATION

LIST OF ACRONYMS

” Hg	Inches of Mercury (Vacuum)
psig	Pounds per Square Inch (Gage)
KV	Kilovolt
ADV	Atmospheric Dump Valve
AFW	Auxiliary Feedwater
AOP	Abnormal Operating Procedure
CAS	Central Alarm Station (Security)
CCDP	Conditional Core Damage Probability
CCNPP	Calvert Cliffs Nuclear Power Plant Units 1 and 2
CEA	Control Element Assemblies
CEDM	Control Element Drive Mechanisms
CENG	Constellation Energy Nuclear Group, LLC ‘s
CFR	Code of Federal Regulations
CIV	Combined Intercept Valves
CPU	Central Processor Units
CR	Condition Report
CRS	Control Room Supervisor
DTCS	Digital Turbine Control System
EDG	Emergency Diesel Generator
EHC	Electro-Hydraulic Control
EOP	Emergency Operating Procedure
I&C	Instrumentation and Controls
IDS	Intrusion Detection System
IMC	Inspection Manual Chapter
IRT	Incident Review Team
ISFSI	Independent Spent Fuel Storage Installation
LCO	Limiting Condition for Operation (TS)
Mark VI DTCS	Mark VI Digital Turbine Control System (Vendor-Supplied)
MDAFW	Motor-Driven Auxiliary Feedwater
MG	Motor Generator
MSIV	Main Steam Isolation Valve
NRC	Nuclear Regulatory Commission
OCA	Owner Controlled Area
OD	Operability Determination
ODMI	Operational Decision Making Instruction
PORV	Primary Power Operated Relief Valve
PPC	Plant Process Computer
PRA	Probabilistic Risk Assessment
PTR	Post-Trip Review
RCP	Reactor Coolant Pumps
RCS	Reactor Coolant System
RO	Reactor Operator

ATTACHMENT 3 – SUPPLEMENTAL INFORMATION

ROP	Reactor Oversight Process
RPS	Reactor Protection System
SAS	Secondary Alarm Station (Security)
SG	Steam Generator
SIT	Special Inspection Team
SM	Shift Manager (SRO)
SOE	Sequence of Events
SPAR	Standardized Plant Analysis Risk
SRA	Senior Risk Analyst
SRO	Senior Reactor Operators
ST	Surveillance Test
STA	Shift Technical Advisor (SRO)
TBV	Turbine Bypass Valves
TCV	Turbine Control Valve
TDAFW	Turbine-Driven Auxiliary Feedwater
TS	Technical Specification
TSV	Turbine Stop Valves
UFSAR	Updated Final Safety Analysis Report
UV	Under-Voltage
WCS	Work Control Supervisor (SRO)