



UNITED STATES  
NUCLEAR REGULATORY COMMISSION  
REGION III  
2443 WARRENVILLE ROAD, SUITE 210  
LISLE, IL 60532-4352

February 14, 2012

EA-11-241  
EA-11-243

Mr. Anthony Vitale  
Vice-President, Operations  
Entergy Nuclear Operations, Inc.  
Palisades Nuclear Plant  
27780 Blue Star Memorial Highway  
Covert, MI 49043-9530

SUBJECT: FINAL SIGNIFICANCE DETERMINATION OF YELLOW AND WHITE FINDINGS  
WITH ASSESSMENT FOLLOWUP AND NOTICE OF VIOLATION  
NRC INSPECTION REPORT NOS. 05000255/2011019 AND 05000255/2011020  
PALISADES NUCLEAR PLANT

Dear Mr. Vitale:

This letter provides you the final significance determination of the preliminary Yellow finding discussed in our previous communication dated November 29, 2011, which included U.S. Nuclear Regulatory Commission (NRC) Inspection Report No. 05000255/2011014. The finding involved the loss of the left train of direct current (DC) power on September 25, 2011.

It also provides you the final significance determination of the preliminary White finding discussed in our previous communication also dated November 29, 2011, which included NRC Inspection Report No. 05000255/2011016. The finding involved the failure of the safety-related service water pump (P-7C) on August 9, 2011, due to intergranular stress corrosion cracking on coupling #6.

At your request, regulatory conferences were held on January 11, 2012, to discuss your views on each of these issues. During each of the conferences, you and your staff described Entergy's assessment of the significance of the findings and the corrective actions taken to resolve them, including the root cause evaluation of the findings. You attributed the root cause of the loss of the DC bus to an organizational issue where senior Entergy management had not established a sufficiently sensitive culture of risk recognition and management, which resulted in Palisades employees not recognizing the industrial safety and plant operational risks involved with the panel ED-11-2 breaker maintenance. You attributed the root cause of the failure of the service water pump P-7C coupling to be a design failure, in that, you failed to recognize that the pump coupling procurement specification did not ensure all critical material testing requirements for use in the service water operating environment.

During the conferences, you provided your perspective that the NRC's risk assessment was overly conservative in assessing the risk significance of both issues, and you discussed specific instances where your staff indicated that a different risk value should be used. You concluded that the loss of DC bus issue was best characterized as having low to moderate risk and that the service water coupling issue was of very low safety significance. Enclosure 1 provides our

detailed assessment of the major points that you raised during both regulatory conferences, along with our final risk assessments. Additionally, Enclosure 2 provides a revised timeline for the loss of DC bus event. The revised timeline reflects information you provided following completion of the special inspection. While this information did not affect the risk assessment, it is enclosed for clarity on when events occurred.

After considering the information developed during the inspections, the additional information you provided in your letter dated January 5, 2012 (ML120100495), and the information you provided during the regulatory conferences, the NRC has concluded that the finding for the loss of the DC bus is appropriately characterized as Yellow, a finding having substantial safety significance. Furthermore, the NRC has concluded that the finding for the failure of service water pump P-7C is appropriately characterized as White, a finding of low to moderate safety significance.

You have 30 calendar days from the date of this letter to appeal the staff's determination of significance for the identified Yellow and White findings. Such appeals will be considered to have merit only if they meet the criteria given in NRC Inspection Manual Chapter 0609, "Significance Determination Process," Attachment 2. An appeal must be sent in writing to the Regional Administrator, Region III, Suite 210, 2443 Warrenville Road, Lisle IL 60532.

The NRC has also determined that violations were associated with the findings, as cited in the enclosed Notice of Violation (Notice). The circumstances surrounding the violations were described in detail in NRC Inspection Report Nos. 05000255/2011014 and 05000255/2011016. In accordance with the NRC Enforcement Policy, the Notice is considered to be escalated enforcement action because it is associated with findings above Green.

The NRC has concluded that information regarding the reasons for the violations, the corrective actions taken and planned to be taken to correct the violations and prevent recurrence, and the date when full compliance was achieved, is already adequately addressed on the docket in NRC Inspection Report Nos. 05000255/2011014 and 05000255/2011016, and during the regulatory conferences. Therefore, you are not required to respond to this letter unless the description therein does not accurately reflect your corrective actions or your position. In that case, or if you choose to provide additional information, you should follow the instructions specified in the enclosed Notice.


As a result of our review of Palisades' performance, including these Yellow and White findings in the Initiating Events Cornerstone, we have assessed the plant to be in the Degraded Cornerstone column (Column III) of the NRC's Action Matrix, as of the fourth quarter of 2011. Therefore, we plan to conduct a supplemental inspection using Inspection Procedure 95002, "Supplemental Inspection for One Degraded Cornerstone or Any Three White Inputs in a Strategic Performance Area," when your staff has notified us of your readiness for this inspection. This inspection procedure is conducted to provide assurance that the root cause and contributing causes of risk significant performance issues are understood, the extent of condition and the extent of cause are identified, and the corrective actions are sufficient to prevent recurrence. In addition, this procedure is conducted to provide an independent determination of whether safety culture components caused or significantly contributed to the risk-significant performance issues.

A. Vitale

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In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosures, and your response, if any, will be made available electronically for public inspection in the NRC Public Document Room or from ADAMS, accessible from the NRC Web site at <http://www.nrc.gov/reading-rm/adams.html>. The NRC also includes significant enforcement actions on its Web site at <http://www.nrc.gov/reading-rm/doc-collections/enforcement/actions>.

Sincerely,



Cynthia D. Pederson  
Acting Regional Administrator

Docket No. 050-00255  
License No. DPR-20

Enclosures:

- 1) Analysis of Licensee Risk Information
- 2) Palisades Event Timeline
- 3) Notice of Violation

cc w/encl: Distribution via ListServ

ANALYSIS OF LICENSEE RISK INFORMATION  
LOSS OF DIRECT CURRENT (DC) BUS (EA-11-243)

During the regulatory conference, the licensee made four major points regarding the risk analysis for the loss of D11-2 inspection finding. These points are described below, followed by the NRC's evaluation of them.

1. The operator action for preventing challenge of the pressurizer safety relief valves (i.e., controlling pressurizer level via charging pumps) was a simple trip of the operating charging pumps. Furthermore, the time available for the action allowed for recovery of failed attempts.
2. The pressurizer safety relief valves were satisfactorily tested for steam, transition, and water relief as part of actions taken following the 1979 Three Mile Island (TMI) event. These tests supported the use of generic failure rates.
3. Actions to restore direct current (DC) power were simple and straightforward, once the fault condition was cleared, and there were two options to restore DC power. Considering both options, the total effective human error probability is  $1E-2$ .
4. Auxiliary feedwater (AFW) pump, P-8A remained available for manual start from the control room.

NRC Evaluation

The NRC determined that the assumptions regarding the first two key points had the greatest contribution to the final significance determination process (SDP) result.

1. The NRC did not agree that the operator action to control pressurizer level was a simple trip of the charging pumps. For this specific event, pressurizer level increased to approximately 98 percent before the operators took control and reduced charging flow. The NRC considered the action to control level to be complex because of the difficulty controlling primary temperature, the difficulty controlling secondary pressure, and the operator workload in performing multiple concurrent tasks during the event, including performing steps of Emergency Operating Procedure (EOP) 9.0, "Functional Recovery." The time available to take effective mitigating action was dependent on several parameters, including charging flow, auxiliary feedwater flow, and the time to complete boration requirements specified in the EOPs. Considering the spectrum of potential plant and operator responses, the NRC staff concluded that the time available would, in most cases, provide little additional margin for recovery of failed attempts.
2. The NRC investigated the safety relief valve tests conducted as part of the TMI action plan and determined that the tests did not present sufficient data to establish the reliability of the valves under water relief conditions. Specifically, of 31 tests, only 5 water tests were conducted for the model of valve used by Palisades, and 1 of these 5 tests was not successful. During the regulatory conference, the NRC requested additional plant-specific information to justify use of a revised stuck open relief valve

failure probability estimate. Following the conference, the NRC was informed that no additional information was available. Therefore, the failure probability used in the preliminary SDP evaluation was the best available information to support the final significance determination.

3. Given the NRC position on the first two points, the NRC concluded that the SDP result was not overly sensitive to the human error probability for operators failing to recover DC power. The NRC acknowledged that the possibility of recovering DC power by aligning the alternate charger (Battery Charger #3) did exist, since the charger was unaffected by the transient. The NRC performed a sensitivity evaluation using the licensee's value for DC power recovery and concluded the likelihood of the operators successfully performing this action was not sufficiently high to change the overall SDP result.
4. For AFW pump P-8A, which was affected by the loss of DC and preferred alternating current (AC) power, the NRC modified its analysis to more accurately capture the effect of the finding on the pump function. The revised analysis assumed that pump function could have been recovered with a failure probability of  $1E-2$  by restoring power to DC bus 11-1 and preferred AC power or through manual operation. However, credit for the pump in the analysis did not change the final SDP conclusion.

Finally, the NRC revised its analysis to remove credit for successful transition to shutdown cooling following a stuck open pressurizer safety relief valve. This change was made to be consistent with the licensee's evaluation of the finding. In the final analysis, this change did not affect the final SDP conclusion. The NRC's final conditional core damage probability (CCDP) was  $6.5E-5$ , indicating that the finding was of substantial safety significance or Yellow.

ANALYSIS OF LICENSEE RISK INFORMATION  
FAILURE OF SERVICE WATER PUMP P-7C (EA-11-241)

During the regulatory conference, the licensee made three major points regarding the risk analysis for the failure of the service water (SW) pump coupling. These points are described below, followed by the NRC's evaluation of them.

1. The coupling failure events on the P-7C SW pump were considered repeated independent failures of a single component. The events occurred too far apart in time to have more than a negligible impact on the common cause failure probability. This was based on the application of NUREG/CR-6268, "Common-Cause Failure Database and Analysis System: Event Data Collection, Classification, and Coding," and the Draft NUREG "Common-Cause Failure Analysis in Event and Condition Assessment: Guidance and Research."
2. An approximate model to derive the initiating event frequency (IEF) for a loss of service water (LOSW) was applied to quantify the frequency increase over the base case value due to the service water pump coupling failures for the degraded condition (i.e., when Type 416 Stainless Steel was used as the service water pump coupling material). This model assumed that a pump-induced loss of service water can be caused by failure of the two normally running SW pumps and failure or unavailability of the standby pump.

Additionally, the NRC approach to adjust the IEF for a loss of service water could overstate the significance of equipment failure and it did not adequately isolate the contributions from pump related and non-pump related failure causes.

3. The as-found condition of SW pump P-7A and P-7B couplings, along with assumptions about the crack growth rate in the SW pump couplings, were used to conclude that the "failure probability of the P-7A and P-7B pumps during the P-7C allowed outage time was small" and that the common-cause term applied in the IEF calculation was conservative.

NRC Evaluation

1. NRC agrees that the coupling failure events occurred far apart in time, but determined that aspect was not enough to rule out potential common cause failure (CCF) for this performance deficiency. The purpose of NUREG/CR-6268 is to support CCF data collection, coding, and analysis and to summarize how data on operational events should be gathered, evaluated, and coded; along with a process for estimating CCF parameters used for probabilistic risk assessment (e.g., alpha factors). Therefore, NUREG/CR-6268 is not a suitable reference on which to treat the potential CCF in the NRC's significance determination process (SDP). Although the details of the specific failure of service water pump P-7C would be considered during our data collection and evaluation process, this would be done solely for the purpose for supporting future CCF parameter updates.

When performing event or condition analysis, NRC assesses the risk incurred not only in the as-found conditions of the observed failure(s) but also, and more importantly, the contribution of potential events associated with the performance deficiency that did not occur but still represent a risk to public health and safety. In other words, when performing an SDP event assessment, the NRC assessment considers not only what actually happened, but also what could have happened with respect to the performance deficiency. Even if only one failure had been observed, considerations for potential CCF, in addition to potential for other equipment failures, would still be included in the SDP risk assessment. In this case, the observed failure was associated with a proximate cause (e.g., inadequate design control and failure to prevent the recurrence of a condition adverse to quality) capable of impacting other components within the same common cause component group (CCCG), where CCCG can be defined as a group of (usually similar) components that are considered to share a potential for failing due to the same cause. Therefore, the SDP risk assessment for this finding includes considerations of the potential failure of other equipment in the same CCCG due to the same proximate cause.

2. The NRC determined that the licensee's approximate model to derive the increase in the loss of service water (LOSW) initiating event frequency due to SW pump failure contained non-conservative assumptions, as described below:
  - The model does not include the potential CCF for all three SW pumps. There is an unstated assumption that CCFs can only occur in two normally running trains of service water. However, CCFs that can affect all three trains do not require all three trains to be operating to occur, as the underlying cause can impact the standby train as soon as a demand takes place.
  - The method estimates the contribution of the pump-related failures to LOSW separately. This approach does not account for the cross-product of pump-related and non-pump related failures. For example, it does not include CCF failure of two SW pumps with a failure of the third pump unrelated to the coupling issue. Such combinations would add to the overall risk resulting from the performance deficiency. While the NRC assessment also used an approximate approach, it was based on the use of a mitigating system fault tree to approximate the numerical increase in IEF due to the contribution of the degraded failure rates for the SW pumps and would include the contribution of such cross-products in the overall result.
  - For the CCF of two trains of service water, the assumed repair time is narrowly based on Technical Specification (TS) requirements (i.e., 6 hours) for continued operation following the failure of two SW pumps. There is an incorrect assumption that the CCF risk is limited to the 6-hour TS shutdown period. There would be additional CCF risk beyond this period since the system would still be needed to mitigate plant events. In addition, the repair time for the pumps would in all likelihood exceed the 6-hour shutdown period.

The NRC did use an approximate ratio method to adjust the IEF for a LOSW event. This approach was implemented as a substitute approach to explicitly modeling the SW system contributions to the IEF. Following the comments provided in the licensee's response to the SDP assessment, a sensitivity analysis was pursued using a more explicit method under implementation by Idaho National Laboratory (INL) that includes systems such as SW via a support system initiating event (SSIE) fault tree model. INL maintains and supports the risk assessment models for the individual sites used for a range of risk-informed activities at the NRC. As part of the support provided by INL, a significant number of models have been updated to include SSIE fault tree modeling, as part of an on-going effort. This effort was initiated in order to include an explicit method of predicting IEF (as opposed to system unreliability or unavailability) for events that can cause a reactor trip as well as affect the systems required to mitigate the event (e.g., such as loss of service water). Construction of the SSIE modeling approach in the NRC risk models conforms to guidance provided in Electric Power Research Institute (EPRI) Technical Report 1016741, "Support System Initiating Events," which was developed by EPRI in cooperation with the NRC and INL (under the provisions of the EPRI-NRC Research memorandum of understanding) with input from a broad spectrum of the PRA community.

At the time the NRC conducted its preliminary risk evaluation, the LOSW SSIE fault tree for Palisades was not sufficiently developed in order for it to be used to assess the risk significance of the SW finding. However, since then, INL has developed a revised Palisades risk model that incorporates a new SSIE model for the SW system. This new Palisades risk model was used to perform a sensitivity analysis in order to benchmark the preliminary SDP result (communicated in Inspection Report 2011-016) using a diverse method of analysis. The risk result using this new risk model corroborated the final risk result using the approximate ratio method used during the preliminary SDP risk evaluation. In other words, both approaches used by the NRC reached the same conclusion that the delta core damage frequency risk significance of this issue was greater than  $1.0E-6/\text{year}$  (i.e., the threshold for a Green/White Finding). This result provided confidence in the original risk results performed by NRC for the SW pump coupling issue identified in the SDP.

3. The NRC considered the contention regarding assumptions about the crack growth rate in the SW pump couplings and other as-found considerations made in the licensee's analysis; however, one of the basic principles of CCF treatment in event and condition assessment (ECA) for SDP assessments is that observed failures are explicitly included (e.g., the failure of the P-7C coupling) while successes are treated probabilistically. The underlying philosophy in this approach is to account for the whole spectrum of potential outcomes that produce a risk increase resulting from the introduction of the performance deficiency, and not just the actual conditions observed. In this context, the remaining operating life of the P-7A and P-7B SW pumps that the licensee estimated in its metallurgical analyses is considered as a "success" that is treated probabilistically in the SDP evaluation. Furthermore, consideration of CCF for these pumps is not limited to only coupling issues, but also includes other potential failures linked by the same proximate cause. Therefore, for NRC SDP assessment purposes, the actual condition of the P-7A and P-7B SW pumps at the time of failure of the P-7C SW pump does not



eliminate CCF potential. The CCF conditional probabilities (alpha factors) for the P-7A and P-7B pumps were quantified using the alpha factor CCF model described in NUREG/CR-5485, "Guidelines on Modeling Common-Cause Failures in Probabilistic Risk Assessment." The most likely scenario was the successful operation of the P-7A and P-7B SW pumps (and this was, indeed, the observed outcome with the P-7C SW pump coupling failures in 2009 and 2011). This is correctly reflected in the conditional probabilities of failure and quantified in the risk calculation.

The NRC's final conditional core damage probability (CCDP) was  $5.4E-6$ , indicating that the finding was of low to moderate safety significance or White.

PALISADES EVENT TIMELINE  
HISTORICAL SEQUENCE OF EVENTS FOR THE  
LOSS OF DIRECT CURRENT (DC) BUS (EA-11-243)

The original timeline was developed independently by the inspectors and documented as Attachment 3 in NRC Special Inspection Report 05000255/2011014. The timeline was created with best estimates based on information available during the first two weeks of the Special Inspection following the September 25, 2011, event. Approximately 6 weeks following the event, the licensee completed an operations transient snap shot assessment, in which the on-shift operators reviewed the event and critiqued their performance. This assessment revealed additional facts and clarifying information which the inspectors and senior reactor analysts independently reviewed. The NRC determined that the revisions to the timeline did not impact the final significance determination result.

The updated historical sequence of events presented below reflects the additional insights gained from the transient snap shot assessment. The licensee initiated Condition Report CR-PLP-2011-06084, "Post Event Organizational Response Was Inadequate," to capture the fact that this assessment was not performed in a timely manner.

Items that are approximate times are preceded with "~" prior to the listed time. During the development of this timeline all times were referenced back to the control room clock, which was the official time and differed from the plant process computer and sequence event recorder times. The term "days" refers to activities that were conducted on the dayshift. The times listed below are based on the 24-hour clock.

October 2010

RFO21 During Refueling Outage 21, ten breakers were replaced inside electrical panel D11-2, associated with the left train 125-Volt direct current (DC) system.

Thursday, September 22, 2011

Days Maintenance personnel began work on work order (WO) 248834-01 to troubleshoot the inoperative green indication lights for door MZ-50, the emergency air lock. All interlocks, indication lights, and limit switches were found to be satisfactory; more troubleshooting was planned for this door indication light issue.

Friday, September 23, 2011

Days Maintenance personnel completed WO 291123-01 to troubleshoot breaker 72-123 in panel D11-2. Maintenance personnel identified that there was no positive load side voltage (this feeds power to the door MZ-50 indicating lights).

15:26 Maintenance personnel completed WO 291123-03 to successfully replace breaker 72-123. Restoration activities included re-installing cover panels inside panel D11-2.

- 16:07 Control room alarms were received by reactor operators (ROs) for the "Generator Field Forcing/Over-Excitation" cycling; and red indication lights flickered for the "Voltage Regulator Control Switch" and "Turbine Generator Exciter Field Breaker Control" alarms. Breaker 72-121, "Main Generator Voltage Regulator Control Power," experienced an intermittent connection during the restoration activities of Panel D11-2.
- 16:17 The ROs experienced a loss of indication for multiple containment isolation valves (CIVs) due to an intermittent loss of power from breaker 72-119. The ROs entered technical specification action conditions (TSAC) for limiting condition for operation (LCO) 3.3.7 (30-day TSAC for CIV indication) and LCO 3.6.3 for all valves (4-hour TSAC to administratively lock the valves closed).
- 16:35 The ROs entered off-normal procedure (ONP) -7.1, "Loss of Instrument Air." The DC power for a junction box common to all three instrument air compressors was a load associated with breaker 72-119. The intermittent loss of power affected the instrument air compressors standby start feature (the instrument air compressors internal "sleep mode" feature remained available to automatically start the air compressors). The feedwater (FW) purity air compressor continued to supply the necessary air to equipment through a control valve that failed open upon the intermittent loss of power and cross-connected the two systems, as designed. The running instrument air compressor C-2A was automatically placed in sleep mode while higher pressure air was supplied by feedwater purity air compressor C-903B.
- ~21:30 Maintenance personnel commenced a new troubleshooting plan and identified: no voltage on the load side of breaker 72-119; misalignments on breakers 72-119, 72-120, 72-121, and 72-123; and a 1/16-inch air gap between the horizontal positive bus bar and the line side positive connection on breaker 72-119. Maintenance personnel also discovered that: the positive feed wire to DC panel D11-2, was 2°degrees Fahrenheit (°F) hotter than the negative wire; the bus had a slight ground; and each breaker's positive horizontal bus bars were hotter than the negative horizontal bus bars.
- 22:23 The ROs exited ONP-7.1 when instrument air compressors C-2A, C-2B and C-2C were identified as available for manual start.

Saturday, September 24, 2011

Days Licensee personnel continued with troubleshooting activities, challenge boards, work package reviews, and temporary modification (TM) EC 31973 development for breaker 72-121, due to Friday's events.

Sunday, September 25, 2011

05:00 Nightshift maintenance personnel held a pre-job brief for TM EC 31973 to discuss implementation of WO 291209-01 to implement the TM. The electrical superintendent made the decision not to have the nightshift electricians begin work.

- ~07:00 Turnover between electrical superintendent and mechanical superintendent (acting maintenance manager) discussed the upcoming evolution to commence work on WO 291209-01 to implement the TM and for work on breakers 72-119, 72-120, 72-121, and 72-123. The turnover highlighted the steps of insulating the bus tie stabs and conducting the evolution in the prescribed sequence for breaker removal to keep positive control over the bus tie stabs.
- ~08:00 Turnover between electrical superintendent and electrical front line supervisor (FLS) discussed the upcoming evolution to commence work on WO 291209-01 to implement the TM and for work on breakers 72-119, 72-120, 72-121, and 72-123. The turnover highlighted the steps of insulating the bus tie stabs and conducting the evolution in the prescribed sequence for breaker removal to keep positive control over the horizontal bus tie stabs.
- ~08:30 A pre-job brief for performing work on WO 291209-01 was held.
- 11:03 Dayshift maintenance personnel installed TM EC 31973 to power breaker loads from breaker 72-121 from the spare breaker 72-127.
- ~12:45 Dayshift maintenance personnel performed an informal pre-job brief for implementing WO 291194-01, WO 291210-01, and WO 291123-03 for work on breakers 72-119, 72-120, 72-121, and 72-123. The workers and management observers then proceeded to panel D11-2 for fieldwork.
- 14:14 The Duty Station Manager (DSM) updated plant management on breaker work via an email stating: "Breaker 72-119 (top breaker in panel) was removed, breaker 72-120 (spare breaker) removed, and an approximately 1/16-inch gap was found between the copper bus bar and breaker stab was identified as well as minor indications of arcing in this area, and the bus bar hole showed evidence of cross-threading."
- 15:03 Palisades Plant Status:  
Reactor power was approximately 98.5 percent;  
Steam generator (SG) 'A' Level was 65.15 percent;  
SG 'A' pressure was 970.26 pounds per square inch absolute (psia);  
SG 'B' level was 63.96 percent;  
SG 'B' pressure was 983.44 psia;  
Pressurizer level was 57.86 percent;  
Pressurizer pressure was 2063.35 psia;  
Primary coolant system (PCS) average temperature was 559.84°F;  
Charging pump P-55A was in service; and,  
Letdown flow from the PCS was 43.45 gallons per minute (gpm).
- 15:06 Reactor and Turbine Trip occurred. During the work inside 125-Volt DC Panel D11-2, while removing a section of bus bar, the bar rotated and established contact between the positive and negative horizontal bus bars, which caused an electrical fault.
- 15:06 Electrical fault on Panel D11-2 caused the shunt trip breaker 72-01 to open.

Palisades Event Timeline

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- 15:06 Opening of shunt trip breaker 72-01 de-energized the left train 125-Volt DC, D-10L, and D-10R.
- 15:06 Loss of D-10L and D-10R de-energized 120-Volt preferred alternating current (AC) buses Y-10 and Y-30.
- 15:06 Inverter input breaker 72-37 tripped.
- 15:06 The loss of two out of the four preferred AC buses caused a loss of power to two reactor protection system (RPS) channels (RPS is a two-out-of-four logic).
- 15:06 The RPS trip signal caused RPS breakers 3 and 4 to actuate resulting in a reactor trip (a two-out-of-four RPS logic).
- 15:06 Reactor trip initiated a turbine trip.
- 15:06 The ROs entered EOP-1.0, "Standard Post-Trip Actions."
- 15:06 The ROs verified that all control rods were inserted into the core (only the control room supervisor plant process computer lost power, all other RO stations were available, in addition, left train indications to PPC were lost due to the loss of the left train 125-Volt DC).
- 15:06 Main steam isolation signal (MSIS) initiated the right channel based on a two-out-of-four logic made-up for the loss of 120-Volt preferred AC buses Y-10 and Y-30 (low SG pressure sensed).
- 15:06 The right channel MSIS signal initiated closure of the right train main steam isolation valve (MSIV). The left train MSIV closed due to the loss of EY-10 and EY-30.
- 15:06 Safety injection actuation signal (SIAS) occurred based on a two-out-of-four logic made-up for the loss of 120-Volt preferred AC buses Y-10 and Y-30 (sensed low pressurizer pressure). Right channel initiated and started the high pressure safety injection (HPSI) 'A' pump and the low pressure safety injection (LPSI) 'A' pump. As designed, non-safety-related Bus 1E was shed, half of the pressurizer heaters were lost, and charging Pump 'B' would not start (charging Pump 'A' continued to operate.)
- 15:06 The LPSI 'A' and HPSI 'A' pumps do NOT inject due to the PCS pressure being greater than the pumps' shutoff head.
- 15:06 Containment high radiation (CHR) signal received based on a two-out-of-four logic made-up from loss of 120-Volt preferred AC buses Y-10 and Y-30. This initiated the following: both trains of control room heating, ventilation, and air conditioning (HVAC) in emergency mode; only the right train ('B') started, since the left train ('A') had no power; primary coolant pump (PCP) bleed-off valve CV-2099 and letdown isolation control valve CV-2009 closed; and both SG bottom blowdown line control valves CV-767 and CV-768 closed.

- 15:06 Containment isolation signal (CIS) initiated based on a two-out-of-four logic made-up for loss of 120-Volt preferred AC buses Y-10 and Y-30. All containment isolation valves closed. The letdown orifice stop valves closed due to the loss of power to pressurizer level control channel A.
- 15:06 Containment high pressure alarm occurred, but not an actuation signal. The alarm was seen on the left channel based on a two-out-of-four logic, but since the downstream relays in this logic had no power, a containment high pressure actuation signal was not initiated. The right channel did not receive any signals.
- 15:06 Turbine driven auxiliary feedwater (TDAFW) pump P-8B started due to its steam supply control valve CV-0522B failing open on loss of DC power (powered by Panel D11-1) and the AFW actuation signal (AFAS).
- 15:06 The AFAS was received due to a loss of 120-Volt preferred AC buses Y-10 and Y-30 (sensed low SG water level), which made up the two-out-of-four logic. The AFW pump P-8A did not start due to the loss of autostart control power (AFAS) but was still available for manual start from the control room.
- 15:06 The ROs verified that safety-related AC buses 1D and 1C (safety-related 2400-Volt) were available.
- 15:06 Buses 1A (non-safety 4160-Volt) and 1F (non-safety 2400-Volt) did not fast transfer to the startup transformers (received fast transfer signal with loss of power; however, the loss of the left train 125-Volt DC prevented the fast transfer from occurring).
- 15:06 The FW purity air compressor C-903B was lost due to the loss of Bus 1E (at the time compressor C-903B was supplying air to the instrument air header, due to the September 23, 2011, event). Instrument air compressor C-2A was in "sleep mode" and auto started upon a lowering instrument air header pressure.

Inoperable Technical Specification (TS) Related Equipment and TSACs entered by ROs:

- Preferred AC Bus No. 1, Y-10, TSAC 3.8.9 (B);
  - Preferred AC Bus No. 3, Y-30, TSAC 3.8.9 (B);
  - Inverter No. 3, D-08, TSAC 3.8.7 (A.1);
  - Inverter No. 1, D-06, TSAC 3.8.7 (A.1);
  - TS 3.0.3 was entered due to two preferred AC buses INOPERABLE and two inverters INOPERABLE. The ROs exited this at 19:12;
  - Left train 125-Volt DC buses D-10L and D-10R, TSAC 3.8.9 (C);
  - Four atmospheric steam dump valves (ASDVs) lost power due to the master controller being powered from Bus Y-10 and lost the quick-open capability (relay lost power with loss of Y-10), TSAC 3.7.4 (A.1 and A.2); and,
  - PCS unidentified leakage TSAC 3.4.13 (unidentified leakage was >1 gpm for PCP-controlled bleed-off being isolated).
- 15:07 AFW pump P-8C started due to AFAS (pump has one minute time delay.)

- 15:17 The turbine-side RO in control room manually jumpered main generator output breakers to the "open" position (Breakers 25F7 and 25H9), which resulted in PCPs 'A' and 'C' coasting down and stopping.
- ~15:20 Main feedwater pumps 'A' and 'B' turbines were tripped from the control room or locally by operators. Condensate pump 'A' was tripped by the ROs. Condensate pump 'B' was functioning.
- 15:27 The ROs Entered EOP-9.0, "Functional Recovery," due to the loss of two preferred AC buses upon completion of EOP-1.0.
- 15:27 Plant Status:  
Reactor power was 0 percent;  
SG 'A' level was 65.15 percent;  
SG 'A' pressure was 925.42 psia;  
SG 'B' level was 55.56 percent;  
SG 'B' pressure was 969.67 psia;  
Pressurizer level was approximately 66.3 percent;  
Pressurizer pressure was approximately 2140 psia; and,  
PCS average temperature was 536.27°F.
- ~15:30 The ROs entered ONP-2.3, "Loss of DC."
- 15:31 An auxiliary operator (AO) was dispatched to the field to respond to a fire alarm in the AFW pump room. The AO was also directed to manually close CV-0522B (AFW 'B' steam supply control valve) for isolation of TDADF pump P-8B. Level in SG 'A' was approximately 67 percent and level in SG 'B' was approximately 58.6 percent. This rendered the left train of AFW INOPERABLE and the ROs entered TSAC 3.7.5.
- ~15:37 The ROs manually switched pressurizer pressure and level indication instruments over to channel 'B' due to the loss of indication from the loss of power on channel 'A' and actual increased pressurizer level and pressure. With the failure of the controller, the pressurizer control systems were at maximum charging, no letdown (letdown orifice valves were isolated), and no pressurizer spray. After the channel swap, charging pumps 'A' and 'B' were running, with charging pump 'A' at minimum speed.
- ~15:37 Pressurizer spray was able to operate with swapping of controllers.
- ~15:37 Pressurizer pressure increased to a maximum of 2206 psia (indicated on PTR-0122). This was below the first pressurizer code safety valve setting of 2500 psia. (Pressurizer power operated relief valves are isolated at Palisades during normal operations.)
- 15:37 The ROs entered ONP-24.1, "Loss of Preferred AC Bus No. 1 (Y-10)" and ONP-24.3, "Loss of Preferred AC Bus No. 3 (Y-30)."
- 15:42 Letdown heat exchanger inlet safety relief valve RV-2006 lifted when the pressurizer level controller was switched to channel B due to the letdown orifice stop valves.

- opening at ~1537 due to the downstream letdown containment isolation valve CV-2009 being closed on the loss of power; the stop valves were isolated at 1542.
- 15:49 Bus 1E (non-safety 2400-Volt AC lost during event) was restored by operations personnel in the control room (load shed on SIAS) and the associated pressurizer heaters were reenergized.
- ~15:51 Main steam safety valve(s) maintained secondary side pressures, which subsequently maintained PCS temperature, from the start of the event.
- 15:53 The plant process computer (PPC) for control room supervisor was restored.
- 15:55 Operators recognized that pressurizer level reached greater than 62.8 percent, which was the TS limit. The ROs entered TSAC 3.4.9(A.1) and (A.2) to reduce levels to less than the limit. Pressurizer level was approximately 81 percent at this time (62.8 percent was reached at 15:28).
- 15:57 EOP-9.0, Attachment 5, "Safety Injection Throttling Criteria," was met, so the ROs reduced flow on the charging pumps to 0 gpm in an attempt to lower the PCS level in the pressurizer; however, the letdown system was still isolated.
- 15:57 Plant Status:  
SG 'A' level was 97.02 percent;  
SG 'A' pressure was 853.33 psia;  
SG 'B' level was 63.96 percent;  
SG 'B' pressure was 965.86 psia;  
Pressurizer level was 81.17 percent;  
Pressurizer pressure was 2046.04 psia; and,  
PCS average temperature was 532.77°F.
- 15:57 120-Volt preferred AC bus No. 3 (Y-30) was OPERABLE on the bypass regulator. Bus 1E (non-safety 2400 Volt AC) was lost with these actions.
- 15:57 Buses D-10L and D-10R, 125-Volt DC left train, were OPERABLE due to Y-30 being restored and the shunt trip breaker 72-01 re-closed. Upon restoration, generator field breaker 341 automatically opened and instrument air compressor C-2A tripped due to its breaker trip circuit being energized when DC power was restored.
- 15:57 The SG 'A' reaches a maximum level of ~97.02 percent (per PPC).
- 16:02 Charging pump 'B' (P-55B) suction relief valve RV-2096 continued to lift since the start of the event and did not properly re-seat. This caused boric acid storage tank water to fill up the equipment drain tank and spill-over onto the floor in pump cubicle 'B' (backed-up floor drain) instead of being added to the PCS as designed.
- 16:15 Pressurizer level reached a maximum of approximately 98 percent. Main steam safety valve(s) continue to lift to maintain secondary side pressures, which subsequently maintained PCS temperature. Since the isolation of the TDAFW pump



- P-8B at 15:31 and with P-8C AFW running on recirculation, PCS temperature started increasing due to the isolation of this heat removal path.
- 16:21 Procedure ONP-7.1, "Loss of Instrument Air," entered since instrument air compressor C-2A tripped at 15:57 upon restoration of the 125-Volt DC left train. Instrument air compressors C-2B and C-2C were placed in service by the AOs.
- 16:30 Operators in the field manually isolated charging pump P-55B, by closing the discharge and suction isolation valves. This was necessary due to an abundance of water in the cubicle from the improperly seated relief valve RV-2096.
- 16:34 The HPSI and LPSI pumps 'A' were secured due to SIAS throttling criteria being met (were never injecting but started on SIAS signal).
- 16:44 The SG 'B' level reached a maximum of approximately 69.06 percent.
- 16:44 Plant Status:  
SG 'A' level was 90.45 percent;  
SG 'A' pressure was 932.45 psia;  
SG 'B' level was 69.06 percent;  
SG 'B' pressure was 930.70 psia;  
Pressurizer level was 91.94 percent;  
Pressurizer pressure was 1864.13 psia; and,  
PCS average temperature was 539.48°F.
- 16:46 120-Volt preferred AC Bus No. 1 (Y-10) was OPERABLE on bypass regulator. 120-Volt Preferred AC Bus No. 3 (Y-30) was taken off of the bypass regulator and powered from the inverter.
- 16:46 All four ASDVs were OPERABLE with the return of 120-Volt preferred AC power source No. 1, Y-10 (power restored to controller) and the operators began using the ASDVs for heat removal. The main steam safety valves closed and remained closed.
- 17:20 Procedure ONP-4.1, "Spurious Containment Isolation," was entered due to loss of preferred AC buses Y-10 and Y-30, which caused the CIS at 15:06.
- 17:46 The ROs exited EOP-9.0 with restoration of the preferred AC buses and entered GOP-8, "Power Reduction and Plant Shutdown to Mode 2 or Mode 3  $\geq 525^{\circ}\text{F}$ ."
- 18:00 Once the ROs exited EOP-9.0, the criteria was met to reset the SIAS.
- 18:00 Cooling was restored to spent fuel pool heat exchanger (lost during loss of power). The pool temperature was 83.4°F at 15:00 and had risen to 87.4°F by the time the heat exchanger was restored.
- 18:52 The AFW pump P-8B was declared OPERABLE when steam supply control valve CV-0522B was re-opened and controller placed in AUTO.

Palisades Event Timeline

-9-

- 19:09 The ROs exited ONP-24.1, "Loss of Preferred AC Bus No. 1," with restoration of Y-10 and associated loads.
- 19:11 The ROs exited ONP-24.3, "Loss of Preferred AC Bus No. 3," with restoration of Y-30 and associated loads.
- 19:12 The ROs declared Inverter No. 3, D-08, OPERABLE, which enabled the exit of TSAC 3.0.3 with buses Y-10, Y-30, and Inverter D-08 restored.
- 19:12 The ROs exited ONP-7.1, "Loss of Instrument Air," when power was returned to the right channel controller.
- 19:23 Battery charger No. 1 D-15 was still INOPERABLE and TSAC 3.8.4(A.2) was entered by the ROs.
- 19:23 Main station battery left channel D-01 was still INOPERABLE and TSAC 3.8.4(B.1) and 3.8.6(A.1 and A.2) were entered by the ROs due to not being connected to a charger.
- 19:33 The ROs connected battery charger No. 3, D-17, to the 125-Volt DC bus to charge main station battery left channel D-01.
- 20:16 Main station battery left channel D-01 met the TSAC requirement 3.8.6 (A.1) and its terminal voltage was greater than 125-Volt; however, the ROs were still in TSAC 3.8.6(A.2).
- 23:48 The ROs restored pressurizer level to less than 62.8 percent (TS limit) which enabled the exiting of TSAC 3.4.9 (A.1 and A.2).

Monday, September 26, 2011

- 01:23 WO 291210-03 started to remove breaker 72-122 to use those bus tie stabs to replace the ones on breaker 72-119 that were damaged during the event.
- 01:56 Charging pump P-55B was declared OPERABLE by the ROs after leaking suction relief valve RV-2096 was verified to function and water was cleaned up in cubicle.
- 03:00 Breakers 72-119 and 72-120 were installed and restored.
- 04:41 Main station battery left channel D-01 was declared OPERABLE by the ROs and TSACs 3.8.4 and 3.8.6 were exited.
- 06:40 Power was restored back to breaker 72-119 loads and thermography was completed satisfactorily on all of the restored breakers, with no anomalies identified.
- 11:58 Charging pump P-55B was started to initiate double charging and letdown to aid in PCS cooldown and transition to Mode 4 (Hot Shutdown).

- 16:09 The ROs exited ONP-4.1, "Spurious Containment Isolation."
- 16:30 The ROs commenced a PCS cooldown with turbine bypass valve.
- 23:06 Reactor entered Mode 4.

Tuesday, September 27, 2011

- 04:30 Shutdown cooling was placed in-service per GOP-9 and GOP-14 when PCS pressure was less than 265 psia and PCS temperature was less than 300°F.
- 06:33 Reactor entered Mode 5 (Cold Shutdown).

Friday, September 30, 2011

- 20:05 Operations accepted Revision 1 of the 125-Volt DC system operability evaluation.
- 21:31 Reactor entered Mode 4.

Saturday, October 1, 2011

- 02:48 Reactor entered Mode 3.
- 23:30 Reactor entered Mode 2.

Sunday, October 2, 2011

- 01:35 Initial criticality achieved with Group 3 rods at 99.3 inches.
- 02:26 Achieved the Point of Adding Heat.
- 03:27 The MSIVs were opened with no issues on operation of valves.
- 07:37 AFW pump P-8C was secured with no issues.
- 08:24 Reactor entered Mode 1.
- 10:20 Generator output breakers closed.

Monday, October 3, 2011

- 11:50 Reactor power was at 100 percent.

## NOTICE OF VIOLATION

Entergy Nuclear Operations, Inc.  
Palisades Nuclear Plant

Docket No. 50-255  
License No. DPR-20  
EA-11-241 and EA-11-243

During U.S. Nuclear Regulatory Commission (NRC) inspections conducted from September 27 through October 28, 2011, and from October 4 through October 28, 2011, violations of NRC requirements were identified. In accordance with the NRC Enforcement Policy, the violations are listed below:

- A. Title 10 of the Code of Federal Regulations (10 CFR), Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," states, in part, that activities affecting quality shall be prescribed by documented instructions, procedures or drawings of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures or drawings.

Work Orders 291194-01, "Inspect and Replace Breakers 72-119 and 72-120," 291210-01, "Replace Breaker 72-121," and 291123-03, "Inspect 72-123 Installation," all dated September 25, 2011, were developed and implemented to perform work on safety-related Bus ED11-2, associated with the left train 125-Volt Direct Current (DC) safety-related system.

Contrary to the above, on September 25, 2011, the licensee failed to ensure that the work performed on Bus D11-2 through Work Orders 291194-01, 291210-01, and 291123-03, all activities affecting quality, was prescribed by documented instructions or procedures of a type appropriate to the circumstances and accomplished in accordance with the instructions or procedures. Specifically, Work Orders 291194-01, 291210-01, and 291123-03 did not provide logical step progression for the work to be performed. The work orders contained critical steps in the work instructions; however, no critical steps were identified in the work order instructions. The work orders also included action steps in a work instruction note to, "Insulate or support load side bus bars to ensure they do not fault," which was not implemented. In addition, the electricians performing work in the field, attempted to remove a positive horizontal bus bar in Bus D11-2, which was not a prescribed step in the work instructions. As a result, during the work in the field the positive horizontal bus bar rotated and contacted the negative horizontal bus bar that in turn caused an electrical fault, loss of the left train 125-Volt DC safety-related system and loss of both preferred alternating current sources associated with the left train DC system.

This violation is associated with a Yellow Significance Determination Process finding (EA-11-243.)

- B.1. 10 CFR Part 50, Appendix B, Criterion III, "Design Control" requires, in part, that design control measures provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program.

Contrary to the above, in December 2007, the licensee failed to verify the adequacy of the design. Specifically, the licensee modified the design of the P-7C couplings to change the material from carbon steel to 416 stainless steel. The licensee failed to verify that the material was adequate for the environment and working conditions for which it would be subjected. As a result, the licensee failed to identify and evaluate a new failure mechanism which was introduced into the system in the form of intergranular stress corrosion cracking (IGSCC).

- B.2. 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Actions" states, in part, that, in the case of significant conditions adverse to quality, measures shall assure that the cause of the condition is determined and corrective actions taken to preclude repetition.

Contrary to the above, on August 9, 2011, the licensee failed to preclude repetition of a significant condition adverse to quality. Specifically, on September 29, 2009, coupling #7 of safety-related service water pump P-7C failed due to IGSCC. This was a significant condition adverse to quality. The licensee's action to prevent recurrence did not consider all critical factors to prevent IGSCC from recurring. On August 9, 2011, coupling #6 of P-7C also failed due to IGSCC.

These violations are associated with a White Significance Determination Process finding (EA-11-241.)

The NRC has concluded that information regarding the reasons for the violations, the corrective actions taken and planned to be taken to correct the violations and prevent recurrence, and the date when full compliance was achieved, is already adequately addressed on the docket in NRC Inspection Reports Nos. 05000255/2011014 and 05000255/2011016, and during the regulatory conferences held on January 11, 2012.

However, you are required to submit a written statement or explanation pursuant to 10 CFR 2.201, if the description therein does not accurately reflect your corrective actions or your position. In that case, or if you choose to respond, clearly mark your response as a "Reply to a Notice of Violation, EA-11-241 and EA-11-243" and send it to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with a copy to the Regional Administrator, Region III, 2443 Warrenville Road, Suite 210, Lisle, IL 60532, and a copy to the NRC Resident Inspector at the Palisades facility, within 30 days of the date of the letter transmitting this Notice of Violation (Notice).

If you contest this enforcement action, you should also provide a copy of your response, with the basis for your denial, to the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001.

If you choose to respond, your response will be made available electronically for public inspection in the NRC Public Document Room or from the NRC's Agencywide Documents Access and Management System (ADAMS), accessible from the NRC Web site at <http://www.nrc.gov/reading-rm/adams.html>. Therefore, to the extent possible, the response should not include any personal privacy, proprietary, or safeguards information so that it can be made available to the public without redaction.

In accordance with 10 CFR 19.11, you may be required to post this Notice within two working days of receipt.

Dated this 14th day of February 2012

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosures, and your response, if any, will be made available electronically for public inspection in the NRC Public Document Room or from the NRC's Agencywide Documents Access and Management System (ADAMS), accessible from the NRC Web site at <http://www.nrc.gov/reading-rm/adams.html>. The NRC also includes significant enforcement actions on its Web site at <http://www.nrc.gov/reading-rm/doc-collections/enforcement/actions>.

Sincerely,

/RA/

Cynthia D. Pederson  
Acting Regional Administrator

Docket No. 050-00255  
License No. DPR-20

Enclosures:

- 1) Analysis of Licensee Risk Information
- 2) Palisades Event Timeline
- 3) Notice of Violation

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DATE	02/7/12	02/7/12	02/8/12	02/7/12	02/8/12
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DATE	02/06/12	02/06/12	02/9/12	02/13/12	

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<sup>1</sup> NRR concurrence received via e-mail from R. Eul on February 6, 2012.

<sup>2</sup> OE concurrence received via e-mail from R. Eul on February 6, 2012.

Letter to Anthony Vitale from Cynthia D. Pederson dated February 14, 2012

SUBJECT: FINAL SIGNIFICANCE DETERMINATION OF YELLOW AND WHITE FINDINGS  
WITH ASSESSMENT FOLLOWUP AND NOTICE OF VIOLATION  
NRC INSPECTION REPORT NOS. 05000255/2011019 AND 05000255/2011020  
PALISADES NUCLEAR PLANT

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