This report provides the results of the Accident Sequence Precursor (ASP) Program for 2020. In addition, trends and key insights are provided for the past 10 years (2011 through 2020).

U.S. Nuclear Regulatory Commission Accident Sequence Precursor Program 2020 Annual Report

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Summary of ASP Program Results

2020 Results. Based on the review of all licensee event reports (LERs) issued during calendar year 2020 and the results from the Significance Determination Process (SDP), seven events were determined to be precursors. Five precursors were evaluated via an independent Accident Sequence Precursor (ASP) analysis. Two precursors were identified through the Reactor Oversight Process via greater-than-*Green* inspection findings, one of which is a preliminary finding and, therefore, is still pending.

The number of LERs issued and those identified as potential precursors continue to decrease to historically low levels. Four precursors with a conditional core damage probability (CCDP) or increase in core damage probability (ΔCDP) greater than or equal to 10^{-5} were identified after two consecutive years (2018 and 2019) with no high-risk precursors. One of these precursors had a CCDP of greater than 10^{-4}, the first such precursor since 2012.

ASP Trends. Trend analyses of precursor data are performed on a rolling 10-year period (i.e., 2011–2020 for this report). The following table provides the updated results of these analyses:[1]

Precursor Category	Trend
All Precursors	↓
Precursors with a CCDP or ΔCDP $\geq 10^{-5}$	↓
Initiating Events	↓
Degraded Conditions	↓
Emergency Diesel Generator (EDG) Failures	↔
Loss of Offsite Power (LOOP) Events	↓
Boiling-Water Reactors (BWRs)	↔
Pressurized-Water Reactors (PWRs)	↓

Key Insights. The following are some key ASP Program insights based on the 114 precursors identified in the past decade:

- Precursors involving degraded conditions (70 precursors) outnumbered initiating events (44 precursors) by a factor of nearly two.
- Initiating events resulted in 67 percent of all precursors with a CCDP or ΔCDP greater than or equal to 10^{-5} and 79 percent of these were the result of a LOOP.
- Natural phenomena (e.g., severe weather, seismic, etc.) resulted in 39 percent of initiating event precursors.
- EDG failures remain the most frequent (29 percent) cause of degraded condition precursors.
- Almost one-quarter of degraded condition precursors existed for at least 10 years.
- Of the 35 precursors involving degraded condition(s) at BWRs, failures in emergency core cooling systems (40 percent) contributed more than other system failures, followed by failures of EDGs (31 percent) and safety-relief valves (14 percent).
- Of the 35 precursors involving degraded condition(s) at PWRs, failures of EDGs (26 percent) contributed more than other system failures, followed by failures in the auxiliary feedwater system (14 percent), and emergency core cooling systems (9 percent).
- The total risk associated with precursors is dominated by 6 precursors with a CCDP or ΔCDP greater than or equal to 10^{-4}, which account for approximately 53 percent of the total risk due to all precursors. The other 108 precursors account for approximately 47 percent to

[1] Horizontal arrows indicate that no statistically significant trend exists. Up and down arrows indicated that there is a statistically significant increasing or decreasing trend, respectively.

the total risk due to all precursors.

Observations. A review of the ASP Program data and trends for the past decade supports the following observations:

- Current agency oversight programs and licensing activities remain effective as shown by decreasing 10-year trends in the occurrence rate of all precursors (and most precursor subgroups). In addition, the number of LERs and potential precursor identified continues to decrease to historical lows.
- Licensee risk management initiatives are effective in maintaining a flat or decreasing risk profile for the industry.
- There are no indications of increasing risk due to the potential "cumulative impact" of risk-informed initiatives.
- No new component failure modes or mechanisms have been identified, and the likelihood and impacts of accident sequences have not changed.

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1. INTRODUCTION

This report provides the ASP Program results for all LERs issued in 2020. In addition, updated precursor trends and insights are also included.

2. 2020 ASP RESULTS

There were 137 LERs issued in calendar year 2020. From these LERs, 108 (approximately 79 percent) were screened out in the initial screening process and 29 events were selected and analyzed as potential precursors. Of the 29 potential precursors, 7 events were determined to exceed the ASP Program threshold and, therefore, are precursors. An independent ASP analysis was performed to determine the risk significance for five of these precursors. Two precursors were the result of greater than *Green* inspection findings identified in 2020, one of which is a preliminary finding and, therefore, still pending.[2] Note that a *White* finding associated with Surry Power Station (Unit 2) occurred in 2019 and, therefore, is considered as a 2019 precursor for trending purposes. Table 1 provides a brief description of all precursors identified in 2020.

Table 1. 2020 Precursors

Plant/Description	LER	Event Date	Exposure Time	CCDP/ ΔCDP	ADAMS Accession No.
Surry 2, Auxiliary Feedwater System Flow Diversion due to Failed Pump Discharge Check Valve	281-19-002	11/20/19	175 days	*White* Finding	ML20212L517
North Anna 1, Degraded Upper Cylinder Piston Pin Bushing Discovered during Maintenance Activities on EDG	338-20-001	2/18/20	73 days	3×10^{-6}	ML21055A029
Quad Cities 2, Electromatic Relief Valve Failed to Actuate Due to Out-of-Specification Plunger	265-20-002	3/30/20	2 years	3×10^{-5}	ML21029A319
FitzPatrick, High-Pressure Coolant Injection (HPCI) Inoperable due to Oil Leak	333-20-003	4/10/20	37 days	*White* Finding	Preliminary[3]
Brunswick 1, LOOP during Hurricane Isaias	325-20-003	8/3/20	Initiating Event	2×10^{-5}	ML20294A552
Duane Arnold, LOOP Caused by High Winds during Derecho	331-20-001	8/10/20	Initiating Event	8×10^{-4}	ML21056A382
D.C. Cook 2, Manual Reactor Trip and Automatic Safety Injection (SI) Due to Failed Open Pressurizer Spray Valve	316-20-003	9/4/20	Initiating Event	2×10^{-5}	ML21035A236

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[2] Three additional greater than *Green* inspection findings were issued in 2020. However, these three findings, Vogtle Electric Generating Station (ADAMS Accession No. ML20091L428), Browns Ferry Nuclear Plants (ADAMS Accession No. ML20076A950), and Clinton Power Station (ADAMS Accession No. ML20307A569), are not associated with increased risk to core damage (e.g., emergency preparedness, security-related, etc.) and, therefore, are out of the scope of the ASP Program.

[3] A preliminary *White* finding was documented in IR 05000333/2020012 (ADAMS Accession No. ML21020A108).

After further analysis, the remaining 22 LERs identified by the initial LER screening were determined not to be precursors. These events were evaluated not to be precursors by the completion of an ASP analysis (10 events) or acceptance of SDP results (12 events). Additional information on the LERs determined not to be precursors via an ASP analysis or by acceptance of SDP results is provided in Appendix A.

2.1. Decreasing LERs and Potential Precursors

The overall number of LERs and potential precursors continues to decrease to historical lows. Table 2 provides the total of number of LERs reviewed and screened by the ASP Program since 2016 (i.e., when the ASP Program switched to reviewing LERs issued on a calendar-year basis).[4]

Table 2. LERs Reviewed by the ASP Program since 2016

Calendar Year	# of LERs Reviewed	# of Potential Precursors	# of LERs Screened-Out	% LERs Screened-Out
2016	368	62	306	83%
2017	307	48	259	84%
2018	252	38	214	85%
2019	199	35	164	82%
2020	137	29	108	79%

2.2. Evaluation of Other Hazards

Historically, ASP analyses have been focused on the risk due to internal events unless another hazard (e.g., fires, floods, seismic) resulted in a reactor trip (e.g., seismically induced LOOP) or a degraded condition is specific to a hazard (e.g., degraded fire barrier). This limitation was due to the lack of external event modeling in the SPAR models for all plants. However, the incorporation of seismic hazards in all SPAR models was completed in December 2017. Therefore, the seismic risk has been considered in evaluation of all degraded conditions beginning in 2018. To date, no additional precursors have been identified due to the evaluation of seismic hazards due to their minimal risk contribution for the events analyzed thus far.

Although not all SPAR models include internal fires, internal floods, and high winds as hazards, the ASP Program utilizes all modeled hazards for the plant event being analyzed beginning in 2020. The risk from all hazards included in the plant specific SPAR model is aggregated into a single ΔCDP for the analysis of degraded conditions. For plants with SPAR models that do not include specific hazard(s), analyst identifies this as a key modeling uncertainty. This modeling uncertainty is evaluated using other available risk information. In 2020, no additional precursors have been identified due to the evaluation of these other hazards. Although, some contributors such as internal fires may have an impact on overall risk for some of the precursors identified, a review of available risk information indicated that the unmodeled hazards would not have changed the overall analysis conclusions (i.e., whether an event is a precursor or a significant precursor). For example, the Quad Cities ASP analysis (LER 265-20-002) evaluated the lack of internal fire scenarios in the SPAR model. While a substantial risk impact could not be ruled

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[4] The annual number of LERs was determined using the enhanced LERSearch webpage. The lasted revision of the LERs is counted and older revisions excluded from the LER counts provided in this table. Canceled LERs and those associated with telephone notifications or security-related events are also excluded in these counts.

out, the evaluation of internal fire scenarios determined that the ΔCDP would likely stay in the 10^{-5} range if internal fires were included in the SPAR model.

3. ASP TRENDS AND INSIGHTS

This section provides the results of trending analyses performed for several different precursor categories and discusses any insights identified. The purpose of the trending analysis is to determine if a statistically significant trend exists for the precursor group of interest during a specified period. A statistically significant trend is defined in terms of the *p-value*. A *p-value* is a probability indicating whether to reject the null hypothesis that no trend exists in the data. A *p-value* less than or equal to 0.05 indicates that there is 95 percent confidence that a trend exists in the data (i.e., leading to a rejection of the null hypothesis that there is no trend). The data period for ASP trending analyses and insights provided in this report is a rolling 10-year period (i.e., 2011–2020 for this report). Note that the figures in this report only include a trend line if a statistically significant increasing or decreases trend was observed.[5]

3.1. All Precursors

Trending of all precursor analyses provides insights as part of the agency's long-term operating experience program.

- *Trend.* Over the past decade (2011–2020), the mean occurrence rate of all precursors exhibits a statistically significant decreasing trend (*p-value* = 0.00001).[6] See Figure 1 for additional information. A figure containing the historical precursor occurrence rates is provided in Appendix B of the ASP Program Summary Description (ADAMS Accession No. ML20049G020).

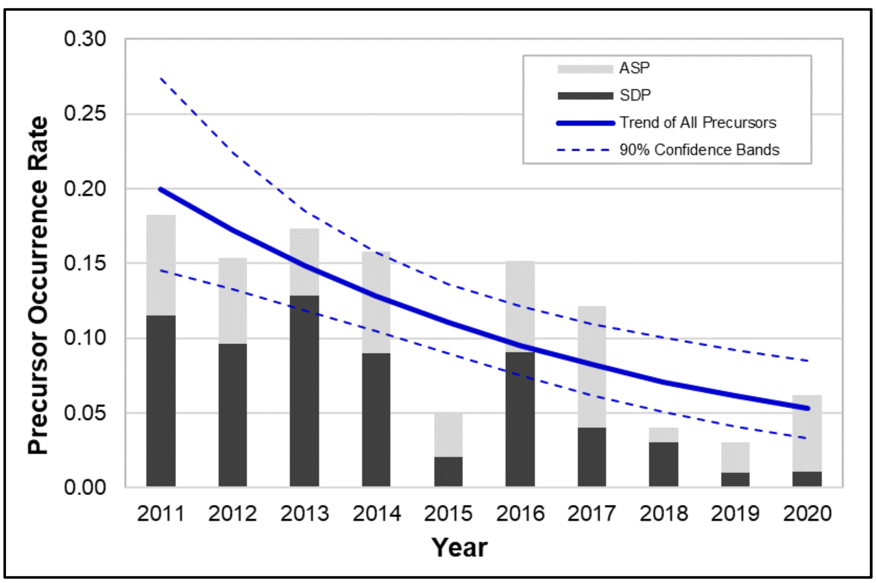

Figure 1. Occurrence Rate of All Precursors

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5 For figures with statistically significant trends, the solid line is the fitted occurrence rate of precursor using a Poisson process model. The dashed lines represent the 90-percent confidence band for the fitted occurrence rate.

6 The occurrence rate is calculated by dividing the number of precursors by the number of reactor years.

- *Use of SDP Results.* Approximately 56 percent of all precursors used SDP evaluation results for the ASP Program purposes. These precursors involve a single unavailability or degradation associated with performance deficiencies in which no initiating event occurred. In a few cases, precursors associated with a single unavailability or degradation due to performance deficiencies were concurrent with an initiating event that were analyzed by both the SDP and the ASP Program, and the SDP risk assessment resulted in a higher risk and, therefore, was used as the final ASP Program result.

3.2. Significant Precursors

The NRC's Congressional Budget Justification (NUREG-1100) uses performance indicators to measure and evaluate performance as part of the NRC's planning, budget, and performance management process. The number of *significant* precursors identified by the ASP Program is one of several inputs to a safety performance indicator used to monitor the agency's Safety Performance Goal 4. No *significant* precursors were identified in 2020. The last *significant* precursor was identified in 2002, which involved concurrent, multiple degraded conditions at the Davis-Besse nuclear power plant. Additional information on all *significant* precursors identified since 1969 is provided in Appendix A of the ASP Program Summary Description.

3.3. Higher-Risk Precursors

Precursors with a CCDP or ΔCDP greater than or equal to 10^{-4} have risks higher than the annual CDF estimated by most plant-specific PRAs.[7] The staff identified one such precursor in 2020—the LOOP at Duane Arnold Energy Center. This is the first precursor with a CCDP or ΔCDP greater than or equal to 10^{-4} identified since 2012. In addition, the staff identified three precursors with a CCDP or ΔCDP greater than or equal to 10^{-5} in 2020 (see Table 1 for additional information). The previous two years (2018 and 2019) are the only years in ASP Program history where no such precursors were identified.

- *Trends*. Over the past decade (2011–2020), the mean occurrence rate of precursors with a CCDP or ΔCDP greater than or equal to 10^{-5} exhibits a statistically significant decreasing trend (*p-value* = 0.00007). See Figure 2 for additional information. In addition, the mean occurrence rate of precursors CCDP or ΔCDP greater than or equal to 10^{-4} exhibits a statistically significant decreasing trend (*p-value* = 0.03).

- *Electrical Issues.* All six precursors with a CCDP or ΔCDP greater than or equal to 10^{-4} involved issues associated with the electrical distribution system and two-thirds were the result of LOOP initiating events.

- *Initiating Event Impact.* Precursors due to initiating events make up approximately 67 percent of all precursors with a CCDP or ΔCDP greater than or equal to 10^{-5}, which is near the historical average. Approximately 80 percent of these precursors were the result of LOOP initiating events.

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[7] Historically, precursors with a CCDP or ΔCDP greater than or equal to 10^{-4} have been called *important* precursors.

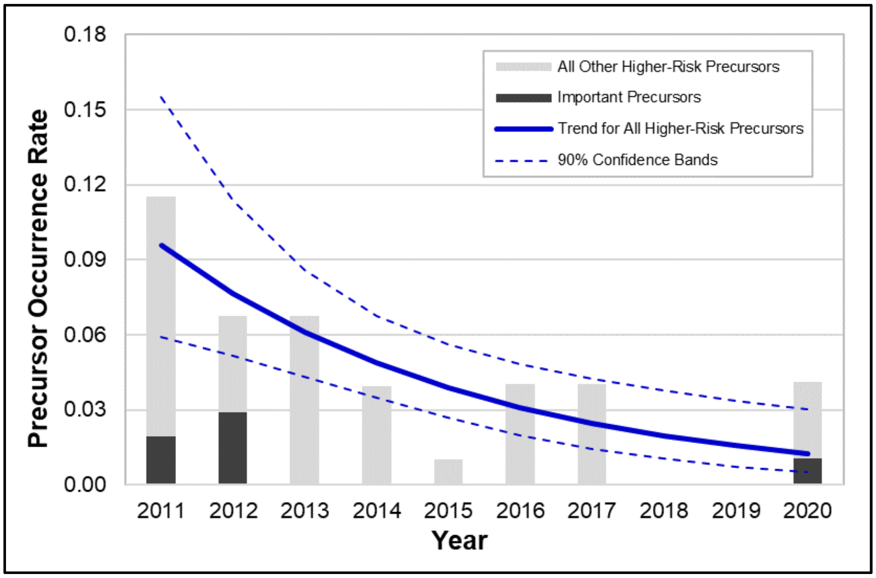

Figure 2. Occurrence Rate of Higher-Risk Precursors

3.4. Precursors Involving Initiating Events and Degraded Conditions

Both initiating events and degraded conditions have the potential to be precursors. An initiating event can (by itself) result in a CCDP that exceeds the ASP Program threshold (e.g., LOOP, loss-of-coolant accident, etc.). In addition, a reactor trip concurrent with a structure, system, or component (SSC) unavailability can result in a precursor. Degraded conditions can be associated with a single or multiple (i.e., "windowed") unavailabilities to determine whether the incremental risk exceeds the ASP Program threshold.

3.4.1. Initiating Events

- *Trend*. Over the past decade (2011–2020), the mean occurrence rates of precursors involving initiating events exhibits a statistically significant decreasing trend (*p-value* = 0.0003). See Figure 3 for additional information.

- *Initiating Event Precursor Breakdown*. Of the 44 precursors involving initiating events, 26 precursors (59 percent) were LOOP events and 17 precursors (39 percent) were complicated reactor trips.[8] Typically, the CCDP estimates for LOOPs are higher than for complicated trips.

- *Initiating Events due to Natural Phenomena.* Of the 44 precursors involving initiating events, 17 precursors (39 percent) resulted from natural phenomena (e.g., severe weather, seismic, etc.). Of these, approximately 76 percent were caused by weather-related LOOP events—5 precursors caused by tornado, 2 precursors caused by the 2011 Virginia earthquake, and 6 precursors caused by other weather-related events.

- *LOOP Trend*. The mean occurrence rate of precursors involving LOOP events exhibits a statistically significant decreasing trend (*p-value* = 0.0008).

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[8] A complicated reactor trip includes a concurrent loss of mitigating equipment.

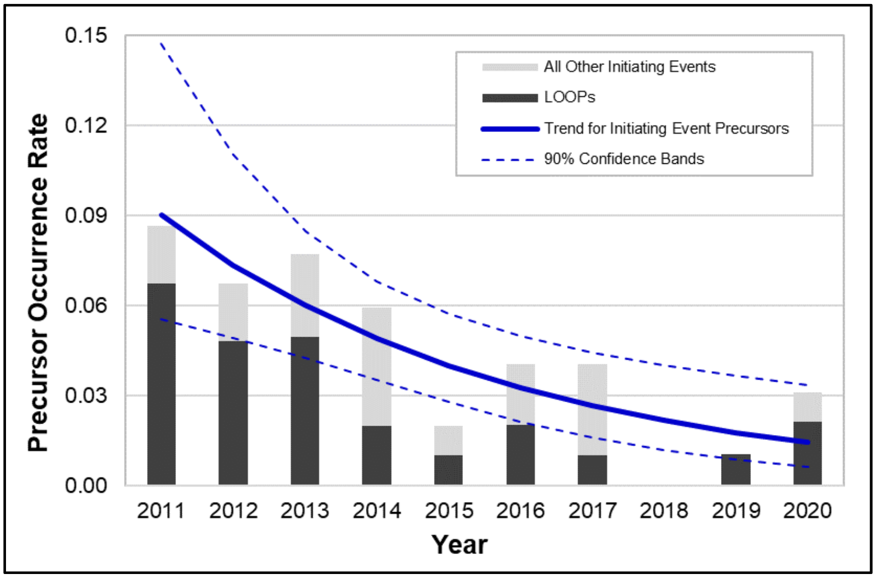

Figure 3. Occurrence Rate of Initiating Event Precursors

- *LOOP with Concurrent EDG Unavailability*. Of the 26 LOOP precursors, two events involved a concurrent unavailability of an EDG. One precursor involved an EDG failure to run due to a leak in the coolant system and the other precursor involved an EDG out of service for maintenance.
- *LOOPs at Multi-Unit Sites*. Of the 26 LOOP precursors, 11 precursors occurred at all units at a multi-unit nuclear power plant (NPP) site, 7 precursors occurred at a single unit on a multi-unit site, and 8 precursors occurred at a single-unit site.

3.4.2. Degraded Conditions

- *Trend*. The mean occurrence rates of precursors involving degraded condition(s) exhibits a statistically significant decreasing trend (*p-value* = 0.007). See Figure 4 for additional information.
- *Degraded Conditions vs. Initiating Events*. Precursors involving degraded conditions (70 precursors) outnumbered initiating events (44 precursors) by nearly a factor of two.
- *EDG Failure Trends*. The mean occurrence rate of precursors involving EDG failures does not exhibit a statistically significant trend (*p-value* = 0.6).
- *Degraded Conditions due to External Hazards.*[9] Of the 70 precursors involving degraded conditions, 17 precursors (24 percent) were associated with the degradation of the protection or mitigation against postulated external hazards (fire, flood, etc.). Of these 17 precursors, 15 precursors were associated with degradations related to floods, 1 precursor was associated with degradation related to internal fires, and 1 precursor was associated with a degradation related to tornadoes.

[9] External hazards often include hazards other than internal events that also occur within the plant boundary such as internal fires.

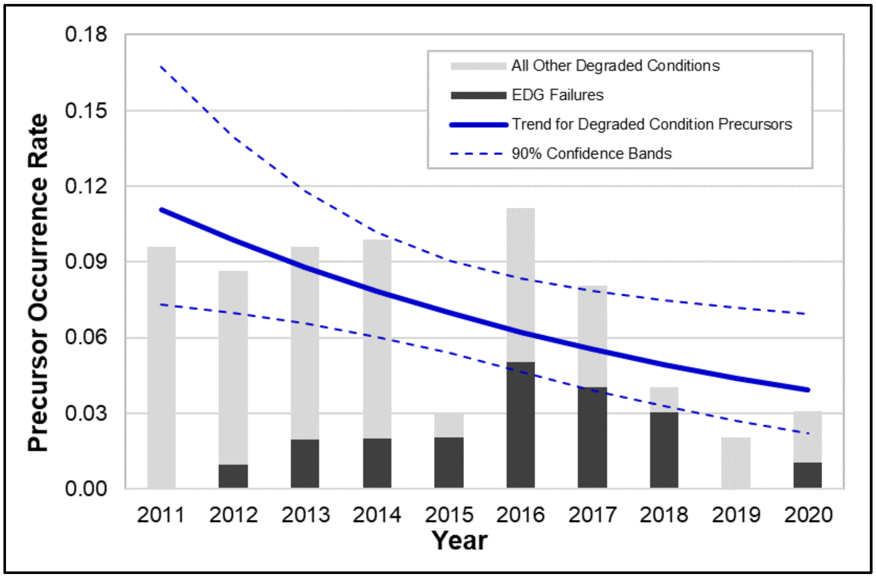

Figure 4. Occurrence Rate of Degraded Condition Precursors

- *Degraded Condition Causes.*[10] Of the 70 precursors involving degraded conditions, 21 precursors (30 percent) were due to inadequate procedures, 21 precursors (30 percent) were due to design deficiencies, and 16 precursors (23 percent) were due to an ineffective corrective action program.

- *Long-Term Degraded Conditions*. Of the 70 precursors involving degraded conditions, 16 precursors (23 percent) involved degraded conditions existing for a decade or longer.[11] Of these, seven precursors involved degraded conditions dating back to initial plant construction.

3.5. Precursors at BWRs and PWRs

Some events (e.g., LOOP initiators, EDG unavailabilities) are not typically influenced by different reactor technologies and can lead to significantly increased risk regardless of whether the affected NPP is a BWR or PWR. However, given the substantial differences in plant design and operating conditions, precursor occurrence rates for the two reactor technologies currently used in the U.S. are studied to glean insights on the potential impact of design differences.[12]

- *Trends*. The mean occurrence rates of precursors that occurred at BWRs does not exhibit a statistically significant trend (*p-value* = 0.1). However, there is a statistically significant decreasing trend (*p-value* = 0.000003) for the mean occurrence rate of precursors that occurred at PWRs. See Figure 5 for additional information.

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10 These causes were determined by a review of inspections findings associated with the applicable precursor events. Typically, these causes were associated with greater-than-*Green* findings. However, causes associated with *Green* findings (i.e., very low safety significance) were considered for events with “windowed” effects that resulted in the event exceeding the precursor threshold.

11 Risk analyses performed as part of the ASP Program and the SDP limit the exposure time to 1 year.

12 Approximately two-thirds of U.S. NPPs are PWRs; therefore, we may expect PWR precursor counts to be about twice as common as the BWR precursor counts.

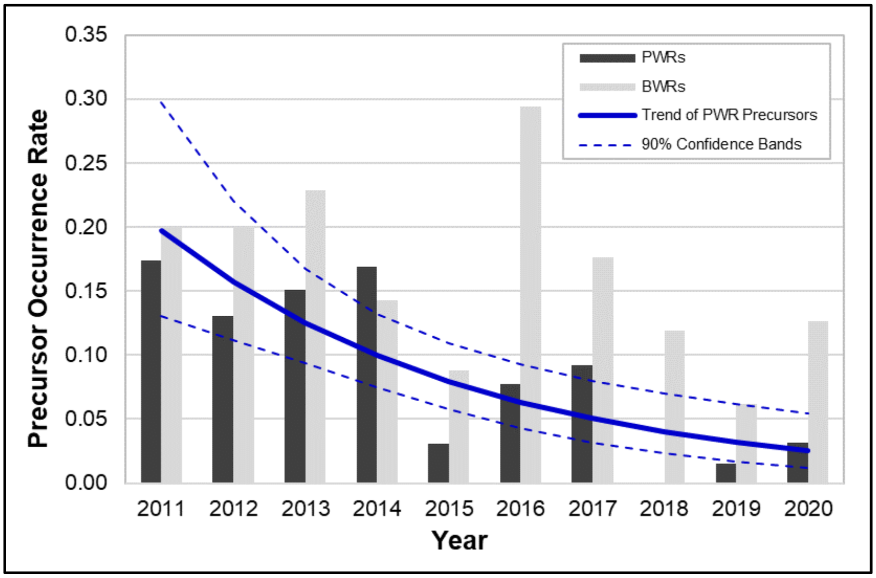

Figure 5. Occurrence Rates of Precursors at BWRs and PWRs

- *LOOPs by Plant Type*. Of the 21 precursors involving initiating events at BWRs, 14 precursors (67 percent) were complete LOOP events. Of the 23 precursors involving initiating events at PWRs, 12 precursors (52 percent) were complete LOOP events.

- *BWR Degraded Condition Breakdown*. Of the 35 precursors involving degraded condition(s) at BWRs, failures in emergency core cooling systems (14 precursors or 40 percent) contributed more than other system failures, followed by failures of EDGs (11 precursors or 31 percent) and safety-relief valves (5 precursors or 14 percent).

- *PWR Degraded Condition Breakdown*. Of the 35 precursors involving degraded condition(s) at PWRs, failures of EDGs (9 precursors or 26 percent) contributed more than other system failures, followed by failures in the auxiliary feedwater system (5 precursors or 14 percent), and emergency core cooling systems (3 precursors or 9 percent).

4. ASP INDEX

The integrated ASP index shows the cumulative plant average risk from precursors on an annual basis. The integrated ASP index is calculated using the sum of CCDPs/ΔCDPs from precursors identified in a given year and is then normalized by dividing that sum by the total reactor-operating years for all NPPs in that year. In addition, the integrated ASP index includes the risk contribution of a precursor for the entire duration of the degraded condition (i.e., the risk contribution is included in each fiscal year that the condition existed). For example, a precursor involving a degraded condition is identified in June 2015 and has a ΔCDP of 5×10^{-6}. A review of the LER or inspection report (IR) reveals that the degraded condition has existed since a design modification that was completed in February 2011. In the integrated ASP index, the ΔCDP of 5×10^{-6} is included in the years 2011–2015 (i.e., the year it was identified and any year that the deficiency existed). The risk contributions from precursors involving initiating events are included in the year that the event occurred.

- *Trends.* The integrated ASP index does not exhibit a statistically significant trend (*p-value* = 0.1).[13] See Figure 6 for additional information.

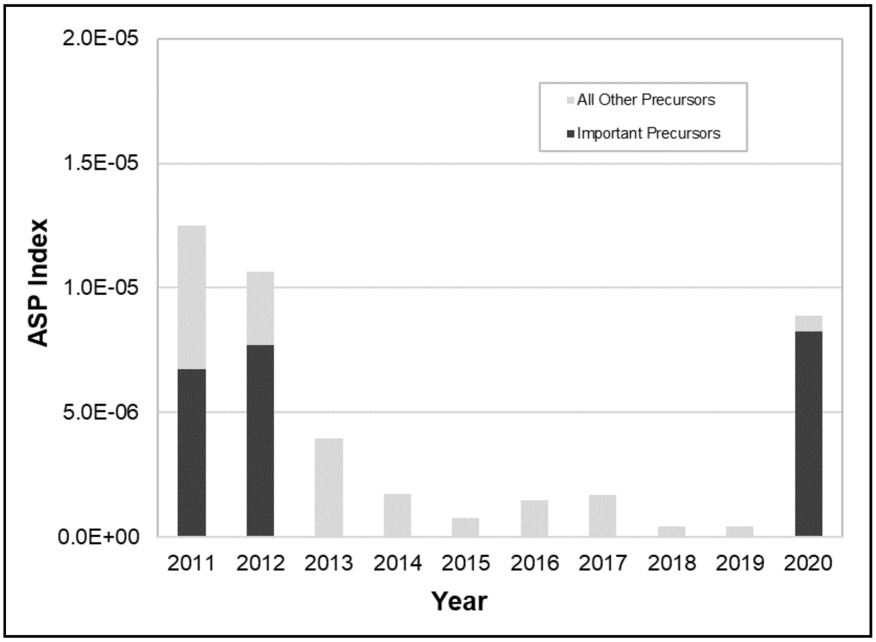

Figure 6. Integrated ASP Index

- *Insights.* The total risk associated with precursors (114 total precursors) is dominated by the six precursors with a CCDP or ΔCDP greater than or equal to 10^{-4}, which account for approximately 53 percent of the total risk due to all precursors. The other 108 precursors account for approximately 47 percent to the total risk due to all precursors.

- *Limitations.* Unlike the trend analyses performed on various precursor groups that are focused on the occurrence rate of precursors, the integrated ASP index is focused on the total risk due to all precursors. Note that precursors evaluated by an independent ASP analysis or an SDP evaluation are limited to a 1-year exposure time. Therefore, the integrated ASP index provides a unique way to evaluate the risk of longer-term degraded conditions over the entire duration of the condition.

5. COMPARISON OF RECENT PROGRAM PESULTS

The five precursors identified in 2020 using an independent ASP analysis were compared with results from Management Directive (MD) 8.3, “NRC Incident Investigation Program,” (ADAMS Accession No. ML18073A200) and SDP analyses, as shown in Table 3. Given the three programs have different functions, it is expected that the results are likely to be different.

6. LER SCREENING QUALITY ASSURANCE REVIEW

The ASP Program leverages current activities to provide the quality assurance review of the LER screening. The primary activity for verifying the effectiveness of LER screening is the participation in the Operating Experience Clearinghouse meetings, which is held up to three times per week. This meeting reviews all event notifications, LERs, regional phone call items,

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13 A log-linear regression was used for the trend analysis of the integrated ASP index.

Table 3. 2020 Independent ASP Analysis Comparison

Event Description	Program Results	SPAR Model/Methodology Improvements and Insights
North Anna 1, LER 338-20-001 Degraded upper cylinder piston pin bushing discovered during maintenance activities on EDG	**MD 8.3.** No evaluation performed.	Credit for FLEX mitigation strategies was provided. Uncertainties associated with FLEX modeling were identified and evaluated via sensitivity analyses.
	SDP. No performance deficiency was identified for this event; therefore, no SDP evaluation was performed.	
	ASP. ΔCDP = 3×10^{-6}; EDG unavailability for 73 days with concurrent unavailability of another EDG for 40 hours. See final ASP analysis (ADAMS Accession No. ML21055A029) for additional information.	
Quad Cities 2, LER 265-20-002 Electromatic relief valve failed to actuate due to out-of-specification plunger	**MD 8.3.** No evaluation performed.	The lack of internal fire scenarios in the SPAR model identified as a key uncertainty and evaluated using other available risk information.
	SDP. No performance deficiency was identified for this event; therefore, no SDP evaluation was performed.	
	ASP. ΔCDP = 3×10^{-5}; safety relief valve failed closed for 1 year. See final ASP analysis (ADAMS Accession No. ML21029A319) for additional information.	
Brunswick 1, LER 325-20-003 LOOP during Hurricane Isaias	**MD 8.3.** No deterministic criteria were met; therefore, a formal risk evaluation was not required. However, a risk evaluation was performed for information purposes, which resulted in CCDP of 2×10^{-5}.	Credit for FLEX mitigation strategies was provided; however, this credit had a minimal impact on the CCDP because station blackout risk was not a dominate contributor.
	SDP. No performance deficiency was identified for this event; therefore, no SDP evaluation was performed.	
	ASP. CCDP = 2×10^{-5}; weather-related LOOP occurred during Hurricane Isaias. See final ASP analysis (ADAMS Accession No. ML20294A552) for additional information.	
Duane Arnold, LER 331-20-001 LOOP caused by high winds during derecho	**MD 8.3.** No deterministic criteria were met; therefore, a formal risk evaluation was not required (ADAMS Accession No. ML21022A415). However, a risk evaluation was performed due to the expected high risk of the extended LOOP, which resulted in CCDPs ranging from 2×10^{-4} to 2×10^{-3}. A focused baseline inspection was performed.	Credit for FLEX mitigation strategies was provided. Uncertainties associated with FLEX modeling were identified and evaluated via sensitivity analyses. SPAR model changes made based on results of new MELCOR calculations for stuck-open relief valve scenarios.
	SDP. No performance deficiency was identified for this event; therefore, no SDP evaluation was performed.	
	ASP. CCDP = 8×10^{-4}; an extended LOOP caused by derecho. See final ASP analysis (ADAMS Accession No. ML21056A382) for additional information.	
D.C. Cook 2, LER 316-20-003 Manual reactor trip and automatic safety injection due to failed open pressurizer spray valve	**MD 8.3.** No deterministic criteria were met; therefore, a formal risk evaluation was not performed.	New inadvertent SI actuation event was incorporated to allow analysis of this event. Human reliability analysis modeling uncertainties identified and evaluated via sensitivity analyses.
	SDP. No performance deficiency was identified for this event; therefore, no SDP evaluation was performed.	
	ASP. CCDP = 1×10^{-5}; inadvertent SI actuation. See final ASP analysis (ADAMS Accession No. ML21035A236) for additional information.	

greater-than-*Green* regulatory findings, NRC communications, and Part 21 notifications and distributes them to the relevant internal technical review groups. When LERs are reviewed by the clearinghouse, the ASP Program manager determines whether the events described meet one or more candidate ASP criteria. If so, the ASP Program manager then ensures that the applicable LER was determined to be a potential precursor via the screening process.

A secondary activity is the search for "windowed" LERs for events that were identified through screening to be potential precursors. As part of the detailed evaluation for LERs corresponding to potential precursors, ASP analysts review other LERs from the applicable plant that may have resulted in initiating events and/or SSC unavailabilities during the same period identified in the LER undergoing the ASP evaluation. As part of these reviews, ASP analysts can identify LERs that were inappropriately screened-out in the initial LER screening.

These two activities resulted in the identification of two conditions, initially screened out of the ASP Program, as potential precursors. Subsequently , it was determined that LERs associated with those conditions were inappropriately screened-out due to ambiguity in the screening criteria associated with fire-related issues and a documentation error, respectively. The screening criteria have been revised accordingly. Note that one of these LERs, LER 338-20-001 (ADAMS Accession No. ML19189A125), was determined to be a precursor after a detailed ASP evaluation was completed.

Appendix A: 2020 ASP Program Screened Analyses

The table in this appendix provides the justification for each licensee event report (LER) that was screened out of the Accident Sequence Precursor (ASP) Program based on a simplified or bounding analysis or by acceptance of Significance Determination Process (SDP) results. Note that the justification reflects the status of the LER (open or closed) at the time of the ASP completion date. While ASP analysts monitor the final SDP evaluation of all findings for including greater-than-*Green* findings as precursors, the screen-out justification is not updated retroactively for events that were initially screened out by an ASP analysis and are later assessed as *Green* (i.e., very low safety significance) in the final SDP evaluation.

Plant	LER	Event Date	Event Description	LER Date	Screen Date	ASP Criterion	Completion Date	Classification
Cooper	298-19-003	12/6/19	Division 2 Service Water Discharge Blockage Resulting in Unplanned Service Water Inoperability	2/4/20	4/19/20	3c	7/23/20	SDP Screen-Out

Analyst Justification. A *Green* finding was identified in inspection report (IR) 05000298/2020050 (ADAMS Accession No. ML20113F037); the licensee event report (LER) is closed. On December 6, 2019, operators were unable to establish service water (SW) flow through the division ‘2’ reactor equipment cooling heat exchanger. The licensee subsequently entered technical specification (TS) limiting condition of operation (LCO) 3.7.3, Condition B. On December 8th , operators were unable to establish SW flow to the division ‘2’ emergency diesel generator (EDG), resulting in a 7-day TS shutdown action statement. Licensee troubleshooting determined the flow blockage was on the common buried SW piping downstream of the division ‘2’ EDG, reactor equipment cooling heat exchanger, and residual heat removal (RHR) heat exchanger. Manual sounding of the discharge canal determined that approximately 15 feet of sediment was blocking the division ‘2’ SW pipe discharge. The silt blockage was removed, and division ‘2’ SW was restored to full operability on December 13th. The licensee implemented a corrective action of ensuring at least 1000 gallons per minute flow through each SW discharge path to prevent the silt from accumulating over the discharge outlets. NRC inspectors determined that the licensee failure to account for all design parameters during the development and installation of a plant modification of the service water system discharge piping in 2014 was a performance deficiency (PD). Specifically, the plant modification increased the separation of the underwater discharge locations, which allowed for sediment accumulation at the discharge point of the SW train not in operation. A backflush of the division ‘2’ reactor equipment cooling heat exchanger completed on November 23rd was the last time division ‘2’ SW was verified able to perform its safety function. A detailed Significance Determination Process (SDP) risk assessment was performed by a Region 4 senior reactor analyst (SRA), which assumed four different periods due to a temporary modification and equipment being unavailable for varying lengths of time. This risk assessment included credit for operators starting the RHR SW booster pump, as directed by the emergency operating procedures (EOPs), which would clear the SW silt blockage in the event low-pressure cooling was required. The risk assessment resulted in an increase in core damage frequency (ΔCDF) of 8×10^{-8} per year. The performance deficiency was determined to be *Green* (i.e., very low safety significance). A search of LERs did not yield any windowed events. The SDP risk assessment is accepted as the ASP Program result, in accordance with Regulatory Issue Summary (RIS) 2006-024, because there was no reactor trip nor windowed event. The risk of this condition is below the ASP Program threshold and, therefore, is not a precursor.

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<tr><td>Browns Ferry 3</td><td>296-20-001</td><td>3/3/20</td><td>Automatic Actuation of Emergency Diesel Generators due to an Offsite Lightning Strike</td><td>5/4/20</td><td>6/18/20</td><td>2a</td><td>7/28/20</td><td>Analyst Screen-Out</td></tr>
<tr><td colspan="9">Analyst Justification. This event is briefly discussed in IR 05000296/2020001 (ADAMS Accession No. ML20128H821); the LER remains open. On March 3, 2020, Unit 3 was in Mode 5 with the alternate decay heat removal (ADHR) system providing decay heat removal because normal shutdown cooling (SDC) was unavailable due planned valve maintenance. A lightning strike caused a partial loss of 161-kV offsite power and resulted in a trip and re-closure of the breaker supplying the common station service transformer 'A'. Offsite power was lost to the Unit 3 start bus ‘1A’ and unit board ‘3A’, which supply power to the 4-kV shutdown boards ‘3A’ and ‘3B’. EDGs ‘3A’ and ‘3B’ automatically started and successfully repowered these buses. EDG ‘3C’ and shutdown board ‘3C’ had been removed from service for maintenance during the event. Shutdown board 3D remained energized from offsite power and, therefore, EDG ‘3D’ was not demanded. This partial loss of offsite power (LOOP) resulted in the loss of ADHR, which was manually restored by operators in approximately 2 hours using temporary diesel generators. Offsite power was successfully restored to the 4-kV shutdown boards ‘3A’ and ‘3B’ within 3 hours. Shutdown cooling was also restored in approximately 3 hours and was run in conjunction with the ADHR system until offsite power was restored to ADHR in approximately 10 hours after the event occurred. A search of LERs did not reveal any other concurrent unavailabilities. Due to the lack of shutdown modeling in the Browns Ferry SPAR model, the risk significance of this event was evaluated using a combination of generic and plant-specific risk insights. During the event, the spent fuel pool (SFP) and equipment pit were hydraulically connected with reactor with water level at 487 inches. The estimated time to boil was approximately 25 hours. During the approximately 2-hour loss of all decay removal, the reactor coolant system (RCS) temperature increased 6°F and reactor water level remained unchanged. Because of (a) the very low failure probability of recovering both ADHR and SDC given the long time to boil (i.e., time available) and the nominal complexity of those actions, and (b) the low failure probability of all redundant and diverse cooling systems (i.e., SDC, ADHR, and temporary diesel generators) considering the typical nominal failure rates for those systems, this event is determined to have very low risk significance and, therefore, is not a precursor.</td></tr>
<tr><td>South Texas 1</td><td>498-20-001</td><td>3/24/20</td><td>Automatic Actuation of Emergency Diesel Generators due to Lockout of Switchyard Electrical Bus</td><td>5/22/20</td><td>6/18/20</td><td>2a</td><td>8/7/20</td><td>SDP Screen-Out</td></tr>
<tr><td colspan="9">Analyst Justification. A Green finding was identified in IR 05000498/2020002 (ADAMS Accession No. ML20212L874); the LER is closed. On March 24, 2020, with Unit 1 defueled and Unit 2 at 100 percent power, the 345-kV south switchyard electrical bus unexpectedly de-energized resulting in a loss of power to standby transformer 2. The loss of standby transformer 2 caused a loss of power to engineered safety features (ESF) 4.160-kV buses 'E1A' and 'E1C' for Unit 1 and bus 'E2B' for Unit 2. EDGs ‘11’, ‘13’, and ‘22’ automatically started and successfully re-energized their respective ESF buses. The cause of this event was a human error made by a transmission and distribution service provider employee while performing planned relay testing in the switchyard. All Unit 1 fuel had been offloaded to the Unit 1 spend fuel pool (SFP) on March 22nd; the RHR system was not in service. The temporary loss of power to buses 'E1A' and 'E1C' resulted in a loss of power to SFP cooling pump ‘1B’. SFP cooling pump '1A' remained running. The loss of bus 'E2B' resulted in a loss of power to SFP cooling pump '2A', which caused a loss of forced circulation to the Unit 2 SFP. Operators restarted SFP cooling pump '1B' in approximately 10 minutes. Forced circulation was restored to the Unit 2 SFP in less than 2 hours when operators restarted SFP cooling pump '2A'. NRC inspectors determined that the licensee failure to adequately assess and manage the risk from switchyard maintenance activities was a PD. A qualitative SDP risk assessment was performed by a Region 4 SRA. As part of this qualitative assessment, the SRA reviewed the licensee risk assessment and determined that it bounded the risk of the event and, therefore, the finding was determined to be Green (i.e., very low safety significance). A search of LERs did not yield any windowed events. The SDP risk assessment is accepted as the ASP Program result, in accordance with RIS 2006-024, because there was no reactor trip nor windowed event. The risk of this event is below the ASP Program threshold and, therefore, this event is not a precursor.</td></tr>
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<tr><td>Hatch 2</td><td>366-20-002</td><td>4/22/20</td><td>HPCI and RCIC inoperable when Required by Technical Specifications</td><td>6/18/20</td><td>7/1/20</td><td>3d</td><td>8/7/20</td><td>Analyst Screen-Out</td></tr>
<tr><td colspan="9">Analyst Justification. This condition is not discussed in any IR to date; the LER remains open. On April 22, 2020, Unit 2 was in the process of starting up following a planned maintenance outage, reactor steam dome pressure exceeded 150 psig with the high-pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) systems inoperable due to not being placed in standby (i.e., the systems would not automatically start on low reactor water level). The plant entered TS LCO 3.5.1, Conditions C and E, which requires operators to verify either HPCI or RCIC was available within 1 hour. The automatic depressurization system (ADS) and the low-pressure emergency core cooling systems (ECCS) were available throughout this event. HPCI and RCIC were returned to operable status in 54 and 88 minutes, respectively. This event was caused by a human performance error. Specifically, oversight of crew performance was narrowly focused on specific tasks, which resulted unidentified gaps in the crew's preparation and execution of the plant startup procedure. A search of LERs did not yield any windowed events. Because the licensee restored HPCI and RCIC within their TS required action times and the exposure times were not longer than the TS allowed outage times for those systems, an evaluation of this condition under the ASP Program to determine whether it is a precursor is not warranted.</td></tr>
<tr><td>Turkey Point 3</td><td>250-20-001</td><td>5/7/20</td><td>Technical Specification Action Not Taken for Unrecognized Inoperable Reactor Protection System and Engineered Safety Feature Actuation System Instrument Channel Functional Units</td><td>6/24/20</td><td>7/1/20</td><td>3a</td><td>8/23/20</td><td>SDP Screen-Out</td></tr>
<tr><td colspan="9">Analyst Justification. A Green finding was identified in IR 05000250/2020002 (ADAMS Accession No. ML20224A289); the LER is closed. On May 7, 2020, a nuclear instrument (NI) channel check identified that the difference between the indicated ΔT and reference ΔT on Eagle 21 channel II exceeded acceptance criterion. This condition resulted in the affected channel functions being declared inoperable. The bistables of the affected functions were placed in the tripped condition within 2 hours, which satisfies the applicable TS action statements. The affected channel functions were subsequently declared operable after the condition was corrected in approximately 12 hours. NRC inspectors determined that the licensee failure to ensure procedure 3-PMI-059.36, “PRNI Protection Set II Channel N-42 Installation of New Current and Streaming Constants at Shutdown,” Revision 0, was properly reviewed for adequacy, was a PD. This performance deficiency was qualitatively screened using the questions in Appendix A of Inspection Manual Chapter (IMC) 0609 and was determined to be Green (i.e., very low safety significance). Specifically, inspectors determined that the degraded instrument channel did not result in a loss of safety function of the reactor protection system (RPS) nor the engineered safety feature actuation system. A search of LERs did not yield any windowed events. The SDP risk assessment is accepted as the ASP Program result, in accordance with RIS 2006-024, because there was no reactor trip nor windowed event. The risk of this condition is below the ASP Program threshold and, therefore, is not a precursor.</td></tr>
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<tr><td>FitzPatrick</td><td>333-20-002</td><td>2/20/20</td><td>Unanalyzed Condition Due to Unprotected Control Circuits Running Through Multiple Fire Areas</td><td>4/14/20</td><td>6/10/20</td><td>3d</td><td>8/23/20</td><td>SDP Screen-Out</td></tr>
<tr><td colspan="9">Analyst Justification. A Green finding was identified in IR 05000333/2020011 (ADAMS Accession No. ML20121A021); the LER is closed. In June 2019, the licensee identified that some nonsafety-related direct-current (DC) control circuits lacked adequate overcurrent protection. Specifically, the DC control circuits for the turbine generator emergency bearing lube oil pump, the emergency seal oil pump , and the reactor feed pump turbine emergency oil pumps were unfused, and the circuit breakers associated with these control circuits were insufficient to prevent a postulated overcurrent event from damaging additional cables or propagating secondary fire. Portions of these nonsafety-related control cables are routed in the same trays that hold safety-related cables through some fire zones. The licensee initially determined that there was no credible hot short scenario that could result in damage to adjacent cables in other fire zones and, therefore, the existing configuration would not degrade plant safety. However, the adequacy of the analysis was later challenged by NRC inspectors, and revised licensee calculations determined that the short circuit current would exceed the values assumed in the initial evaluation resulting in temperatures in excess of the cable insulation rating of 250°C. As a corrective action, the licensee issued a standing order that established compensatory actions for the affected fire areas until the circuit protective devices were installed. The licensee completed adding fuses to the affected nonsafety-related control cables in March 2020. NRC inspectors determined that the licensee failure to protect safe shutdown cables from the effect of postulated fires in accordance with 10 CFR Part 50, Appendix R was a PD. As part of the detailed SDP risk assessment, the Region 1 SRA reviewed the licensee's risk evaluation using their fire probabilistic risk assessment (PRA) model. The licensee's risk evaluation was determined to provide the best estimate of the impact of the PD. The risk assessment used the maximum exposure time of 1 year, which resulted in a ΔCDF of $4{\times}10^{-7}$ per year and, therefore, determined to be Green (i.e., very low safety significance). A search of LERs for the past year identified a reactor scram (LER 333-2020-001) caused by feedwater issues occurred on January 31, 2020. All systems responded as designed during the reactor scram response. No other significant windowed events were identified. Because the reactor scram would not result in an additional risk impact of the electrical cable susceptibility to a potential fire, the SDP risk assessment is accepted as the ASP Program result in accordance with Regulatory Issue Summary (RIS) 2006-024. The risk of this condition is below the ASP Program threshold and, therefore, is not a precursor.</td></tr>
<tr><td>Peach Bottom 2</td><td>277-20-001</td><td>2/26/20</td><td>Emergency Diesel Generator Shutdown Due to Intercooler Low Pressure Results in Condition Prohibited by Technical Specifications</td><td>4/24/20</td><td>6/10/20</td><td>3e</td><td>8/31/20</td><td>SDP Screen-Out</td></tr>
<tr><td colspan="9">Analyst Justification. A Green finding was identified in IR 05000277/2020002 (ADAMS Accession No. ML20223A151); the LER is closed. On February 26, 2020, plant operators started EDG 'E1' for surveillance testing. After running for approximately 20 minutes, the EDG automatically tripped due to low intercooler coolant system pressure. Subsequent licensee investigation revealed that air was introduced into the system during the maintenance activities performed earlier in the month. Therefore, it was determined that the EDG was unable to fulfil its safety function from February 7th until the intercooler coolant system had been fully vented on February 27th (approximately 21 days). NRC inspectors determined that the licensee failure to perform appropriate corrective actions to evaluate and address past EDG intercooler coolant low pressure trips was a PD. A detailed SDP risk assessment was performed by a Region 1 SRA assuming a failure of the EDG 'E1' for an exposure time of approximately 21 days. The risk assessment using the SPAR model and licensee PRA for internal fires resulted in a ΔCDF of $5{\times}10^{-7}$ per year for Unit 2 and $3{\times}10^{-7}$ per year for Unit 3, which include impacts from internal events and other hazards. A search of LERs did not reveal any windowed events. The SDP risk assessment is accepted as the ASP Program result, in accordance with RIS 2006-024, because there was no reactor trip nor windowed event. The risk of this condition is below the ASP Program threshold and, therefore, is not a precursor.</td></tr>
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Plant	LER	Event Date	Event Description	LER Date	Screen Date	ASP Criterion	Completion Date	Classification
Wolf Creek	482-20-002	6/28/20	Faulted Supply Fan Motor Causes Diesel Generator Inoperability Longer than Technical Specification Completion Time	8/27/20	9/29/20	3e	11/19/20	Analyst Screen-Out
Analyst Justification. This condition is discussed in IR 05000482/2020002 (ADAMS Accession No. ML20224A354); the LER remains open. On June 25, 2020, MCR operators noticed that there were no indicating lights lit for the supply fan for EDG 'B'. An operator was dispatched and reported that the breaker for the supply fan was tripped. EDG 'B" was declared inoperable in accordance with TS 3.8.1, Condition B because during the hotter months of the year, the room supply fan is required to be in service to support operability of the EDG. Licensee troubleshooting determined that the fan tripped due to fault on the fan motor. The licensee requested a Notice of Enforcement Discretion (NOED) for an additional 22 hours beyond the 72-hour completion time for TS 3.8.1, Required Action B.4.1. The NRC exercised enforcement discretion for a total period of 94 hours. On June 29th, EDG 'B' was restored to operable status after successful replacement and testing of the EDG 'B' supply fan motor. The licensee evaluated the possibility of running EDG 'B' without its supply fan and determined that while this may shorten the life of some of the equipment in its associated EDG room but the EDG and other safety related equipment in the room would have fulfilled their safety functions for at least 7 days. Since no loss of safety function for the PRA mission time of 24 hours was experienced, this condition is not a precursor. A review of potential windowed events was not needed because there was no loss of safety function.								
Quad Cities 2	265-20-001	3/20/20	Loss of Both Divisions of Residual Heat Removal Low Pressure Coolant Injection due to Swing Bus Failure to Transfer	5/19/20	6/10/20	3d	12/7/20	Analyst Screen-Out
Analyst Justification. No inspection finding was identified for this condition; the LER was closed in IR 05000265/2020002 (ADAMS Accession No. ML20225A008). On March 20, 2020, during the low-pressure coolant injection (LPCI) swing bus surveillance test, motor control center (MCC) '28/29-5' did not auto-transfer from bus '29' to bus '28'. The failure to auto-transfer would have prevented LPCI Loop Select Logic from opening motor operated valves (MOVs) 2-1001-29A/B, resulting in the loss of the LPCI safety function. Following the auto-transfer failure, operators manually restored power to MCC '28/29-5'. The apparent cause of the event was a manufacturing error in the LPCI swing bus time delay relay, which had been installed in 2018. A search for windowed events identified LER 265-2020-002 associated with a failure of ADS valve for an entire fuel cycle that was concurrent with the MCC auto-transfer failure. The effects of these windowed events are provided in the detailed precursor report for LER 265-2020-002. A risk assessment was performed assuming the failure of the automatic bus transfer for MCC 28/29-5 for the maximum exposure time of 1 year. Credit for manual transfer of power for MCC '28/29-5' was not provided, which is potentially conservative. This analysis resulted in a ΔCDP 9×10^{-8} from internal events, seismic hazards, internal floods, high winds, and tornados. The lack of internal fire scenarios in the SPAR model is an uncertainty. However, given the limited nature of the degraded condition and the potential for recovery by the operators, risk impact from internal fire scenarios for this condition is not expected to be significant. The risk of this condition is below the ASP Program threshold and, therefore, is not a precursor.								

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<tr><td>Braidwood 1</td><td>456-20-001</td><td>10/3/20</td><td>The Unit 1 Train A Auxiliary Feedwater Pump was Inoperable Due to a Failed Suction Pressure Lead/Lag Card</td><td>11/22/20</td><td>12/16/20</td><td>3b</td><td>1/4/21</td><td>Analyst Screen-Out</td></tr>
<tr><td colspan="9">Analyst Justification. This condition is not discussed in any IR to date; the LER remains open. On October 3, 2020, during a channel check of AFW pump ‘1A’ suction pressure performed each shift, it was identified that the deviation between the train ‘A’ and ‘B’ pump suction pressures exceeded the acceptance criteria. Specifically, the AFW pump ‘1A’ suction pressure computer point indicated 37.9 psia, while the AFW pump ‘1B’ suction pressure computer point indicated 40.3 psia. This pressure difference exceeded the allowable 4 percent deviation. The local pressures from the pump suctions showed only a 0.8 psia difference. Additional licensee investigation revealed that computer point for the AFW pump ‘1A’ suction pressure failed at a constant value on September 17, 2020 but was not identified until October 3, 2020. This failure was the result of a failed suction pressure lead/lag card. The failure AFW ‘1A’ pump suction pressure signal would result in the failure of the auto-transfer to the ESW as a suction source if its normal suction source (i.e., CST) failed. A search of LERs did not yield any windowed events. The alternate ESW suction source is not included in the Braidwood SPAR model because the CST has a very low probability of failure and has sufficient inventory to maintain the AFW safety function for the PRA mission time. Given the very low failure probability of the CST as a AFW suction source, the availability of the AFW pump ‘1B’ to automatically switchover to ESW if needed, and the ability of operators to manually switchover AFW pump ‘1A’ to ESW, the risk of this condition is qualitatively determined to be below the ASP Program threshold and, therefore, is not a precursor.</td></tr>
<tr><td>Salem 1</td><td>272-20-002</td><td>5/5/20</td><td>RHR availability for Emergency Core Cooling in Mode 4</td><td>7/6/20</td><td>8/18/20</td><td>3d</td><td>1/7/21</td><td>SDP Screen-Out</td></tr>
<tr><td colspan="9">Analyst Justification. A minor finding was identified in IR 05000272/2020003 (ADAMS Accession No. ML20314A149); the LER remains open. On May 5, 2020, a licensee evaluation determined that while in Mode 4, the fluid temperature in the RHR pump suction header could result in pump cavitation during a postulated loss-of-coolant accident (LOCA). Westinghouse report NSAL-09-08 reveals that this issue applies to other Westinghouse plants. The potential for RHR pump cavitation exists in the injection phase regardless of whether the pump suction is aligned to the refueling water storage tank (RWST) or the containment sump. The condition is postulated to occur during both the injection phase, when suction is aligned to the RWST as well as the recirculation phase when suction is aligned to the ECCS sump. This postulated condition results in the inoperability of the RHR system while in Mode 4. The licensee conducted review of the issue, including an adequate extent of condition and historical review. Based on the review the licensee implemented corrective actions to address the potential inoperability of RHR in Mode 4 due to cavitation. A search of LERs did not reveal any windowed events. NRC inspectors determined this issue was minor because it did not adversely affect the mitigating systems cornerstone objective (procedure quality) to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e. core damage). Events evaluated by the NRC as minor findings are not considered risk significant and, therefore, this condition is not a precursor.</td></tr>
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<tr><td>Susquehanna 1</td><td>387-20-002</td><td>7/1/20</td><td>Inoperability of Unit 1 “B” Residual Heat Removal Service Water Pump</td><td>8/27/20</td><td>9/29/20</td><td>3c</td><td>1/7/21</td><td>Analyst Screen-Out</td></tr>
<tr><td colspan="9">Analyst Justification. This condition is not discussed in any IR to date; the LER remains open. On July 1, 2020, residual heat removal service water (RHRSW) pump ‘B’ failed to start during spray pond cooling testing. The plant entered TS 3.7.1, Condition B for one RHRSW subsystem inoperable. The licensee determined that the pump breaker’s closing springs did not recharge following operation on June 21st. Repairs were completed and the RHRSW pump ‘B’ operability was restored on July 2nd. A search of LERs did not reveal any windowed events. A risk assessment was performed assuming the failure RHRSW pump ‘B’ for an exposure time of 260 hours. This analysis resulted in a ΔCDP 1×10^{-7} from internal events, seismic hazards, high winds, and tornados. The lack of internal fire and flood scenarios in the SPAR model is an uncertainty. A review of the Susquehanna Individual Plant Examination (IPE) and Individual Plant Examination for External Events (IPEEE) indicates that flooding and internal fires are small contributors to overall plant risk and it not expected to have a significant risk-impact for this condition. This analysis result is below the ASP Program threshold and, therefore, this condition is not a precursor.</td></tr>
<tr><td>Susquehanna 2</td><td>388-20-002</td><td>8/10/20</td><td>Condition Prohibited by Technical Specifications Due to Drift of Reactor Pressure Switch</td><td>10/7/20</td><td>11/6/20</td><td>3d</td><td>1/7/21</td><td>Analyst Screen-Out</td></tr>
<tr><td colspan="9">Analyst Justification. This condition is not discussed in any IR to date; the LER remains open. On August 19, 2020, channel ‘D’ of the reactor steam dome pressure low permissive pressure switch drifted outside of the TS allowable value. The reactor steam dome pressure low permissive signal prevents over-pressurization of the low-pressure injection systems prior to initiation. Although the drift of channel ‘D’ could have resulted in the low-pressure injection systems experiencing a high pressure of approximately 456 psig, the low-pressure injection systems are designed to withstand a pressure at this level and, therefore, remained available to perform their safety function. Since no loss of safety function was experienced, this condition is not a precursor. A review of potential windowed events was not needed because there was no loss of safety function.</td></tr>
<tr><td>Hatch 1</td><td>321-20-001</td><td>12/3/20</td><td>1A EDG Inoperable Due to Water in the Day Tank</td><td>12/10/20</td><td>2/2/21</td><td>3e</td><td>2/3/21</td><td>SDP Screen-Out</td></tr>
<tr><td colspan="9">Analyst Justification. A Green finding was identified in IR 05000321/2020002 (ADAMS Accession No. ML20218A205); the LER remains open. On May 5, 2020, standing water was observed in the manway of the fuel oil storage tank for EDG ‘1A’. A subsequent fuel sample was analyzed, and it was determined that there was water in the fuel. The associated EDG ‘1A’ day tank was sampled and approximately 15 gallons of water was found. The licensee immediately took actions to drain the water from the tanks. The day tank and fuel oil storage tank were returned to service by May 16th. The licensee determined the water intrusion in the fuel oil storage tank for EDG ‘1A’ came from a nearby pull box. The water was able to pass through the pull-box conduit into the tank enclosure, which flooded via the manway cover because the drain holes were clogged. In addition, the licensee determined the EDG ‘1’A day tank water detection system was not functional due to a calibration error. The detection system was calibrated and returned to service on May 12th. The licensee determined that EDG ‘1A’ would not have been able to perform its safety function with the amount of water in the EDG ‘1A’ day tank. NRC inspectors determined that the licensee failure to promptly identify and correct the water intrusion in the fuel oil storage tank for EDG ‘1A’ was a performance deficiency. A detailed SDP risk assessment was performed by a Region 2 SRA assuming the EDG ‘1A’ would have failed to start for an exposure time of 13 days resulted in a ΔCDF of less than 1×10^{-6} per year for both internal and external hazards. A search of LERs did not reveal any windowed events. The SDP risk assessment is accepted as the ASP Program result, in accordance with RIS 2006-024, because there was no reactor trip nor windowed event. The risk of this event is below the ASP Program threshold and, therefore, this event is not a precursor.</td></tr>
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Plant	LER	Event Date	Event Description	LER Date	Screen Date	ASP Criterion	Completion Date	Classification
River Bend	458-20-003	8/28/20	Weep Holes Discovered in G-Tunnel Wall Result in Inoperable Safety Related Equipment	10/26/20	11/11/20	3c	2/22/21	SDP Screen-Out
Analyst Justification. A *Green* finding was identified in IR 05000458/2020004 (ADAMS Accession No. ML21041A546); the LER remains open. On June 10, 2020, weep holes were identified in exterior wall of the heating, ventilation, and air conditioning (HVAC) chamber located adjacent to the 'G' tunnel, which created the unknown potential of water infiltration during a probable maximum precipitation (PMP). Because the original construction had a simple grating at the top, which was previously corrected, precipitation could collect in the bottom of the tunnel. As part of the corrective action, weep holes were drilled in the exterior wall to allow standing water to drain to the environment. During a postulated PMP event, water could pool within the excavation area covering these weep holes. This condition allowed for the possibility for water to infiltrate this chamber and subsequently could have flowed into the fan ducting and into the G tunnel. A licensee engineering analysis determined that water flow from the weep holes would exceed the capability of the three sump pumps located in the area. Since the 'G' tunnel is interconnected with 'E' and 'F' tunnels, safety-related equipment in these tunnels could have also been adversely impacted. Specifically, service water motor-operated valves are located in the tunnel complex could be affected. On June 22nd, the work was completed to plug the weep holes in accordance with an approved engineering design change. NRC inspectors determined that the licensee failure to ensure that the G tunnel, a safety-related structure, was suitably designed to withstand the effects of natural phenomena in accordance with 10 CFR Part 50, Appendix A, Criterion 2 was a performance deficiency. A detailed SDP risk assessment was performed by a Region 4 SRA evaluating the potential for rain to result in flooding in the 'G' tunnel resulted in a ΔCDF of 4×10^{-7} per year. A search of LERs did not reveal any windowed events. The SDP risk assessment is accepted as the ASP Program result, in accordance with RIS 2006-024, because there was no reactor trip nor windowed event. The risk of this event is below the ASP Program threshold and, therefore, this event is not a precursor.								
Beaver Valley 1	334-20-001	9/16/20	Intake Structure Interconnecting Flood Door Found Open Resulting in a Loss of Train Separation for the Reactor Plant River Water System	11/13/20	12/15/20	3f	2/22/21	SDP Screen-Out
Analyst Justification. A *Green* finding was identified in IR 05000334/2020004 (ADAMS Accession No. ML21043A018); the LER is closed. On September 16, 2020, a flood door separating the two trains of the river water system was found to be open. The MCR was notified and the interconnecting flood door was subsequently closed. A past operability review performed by the licensee determined that with this door open, the river water system was inoperable according to TS due to the loss of train separation during a postulated internal flood in one of the cubicles. The amount of time that the flood door was left open prior to discovery could not be determined, but the maximum exposure time was 218 days. NRC inspectors determined that the licensee failure to adequately translate design basis requirements established in the Unit 1 final safety analysis report regarding the position of the interconnecting flood doors between pump cubicles in the intake structure into specifications, procedures, and instructions was a performance deficiency. A detailed SDP risk assessment was performed by a Region 1 SRA assuming the open flood door, accounting for piping and expansion joint failures in the river water system cubicles, for an exposure time of 109 days (T/2) resulted in a ΔCDF of 3×10^{-7} per year. A search of LERs did not reveal any windowed events. The SDP risk assessment is accepted as the ASP Program result, in accordance with RIS 2006-024, because there was no reactor trip nor windowed event. The risk of this event is below the ASP Program threshold and, therefore, this event is not a precursor.								

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<tr><th>Plant</th><th>LER</th><th>Event Date</th><th>Event Description</th><th>LER Date</th><th>Screen Date</th><th>ASP Criterion</th><th>Completion Date</th><th>Classification</th></tr>
<tr><td>Quad Cities 2</td><td>265-20-003</td><td>7/22/20</td><td>Oscillation Power Range Monitor Count Setpoint Discrepancy Due to Inadequate Instructions</td><td>9/17/20</td><td>10/28/20</td><td>3a</td><td>3/1/21</td><td>SDP Screen-Out</td></tr>
<tr><td colspan="9">Analysis Justification. A minor performance deficiency was reported in IR 05000265/2020003, (ADAMS Accession No. ML20315A134); the LER is closed. On July 22, 2020, during performance of an oscillation power range monitor (OPRM) time test, the OPRM maximum confirmation count setpoint did not match the values in the core operating limits report (COLR). All OPRMs were declared inoperable according to TS. The setpoint was found to be set at 16 counts to trip but the COLR set point is 15 counts. This setpoint discrepancy was corrected and all the OPRMs were declared operable on July 23rd. The cause of the incorrect OPRM count setpoint was due to insufficient work package guidance and a lack of verification to ensure that the work instructions contained the proper setpoints. A licensee evaluation concluded there was sufficient margin in the operating limit minimum critical power ratio to ensure that the existing safety analysis would have supported a maximum confirmation count setpoint of 16 and, therefore, this condition did not result in loss of safety function of the OPRMs. NRC inspectors determined that the licensee failure to include adequate work instructions constituted a performance deficiency. Specifically, the applicable work order package did not direct technicians to update the count setpoint. Inspectors determined the performance deficiency was minor because there was no significant degradation in the safety function and therefore, this condition is not a precursor. The SDP risk assessment is accepted as the ASP Program result, in accordance with RIS 2006-024, because there was no reactor trip. A review of potential windowed events was not needed because there was no loss of safety function.</td></tr>
<tr><td>Vogtle 1</td><td>424-20-002</td><td>9/29/20</td><td>Oil Leak causes Ultimate Heat Sink to be inoperable longer than allowed by Technical Specifications</td><td>11/25/20</td><td>12/16/20</td><td>3f</td><td>3/9/21</td><td>SDP Screen-Out</td></tr>
<tr><td colspan="9">Analyst Justification. A preliminary SDP evaluation has been completed; the final evaluation will be documented in the forthcoming quarterly IR. On September 29, 2020, during quarterly preventive maintenance on gearbox for nuclear service cooling water (NSCW) fan ‘4’, it was discovered that the oil level in the gearbox was low. The last time the gearbox oil level was verified to be full was July 7, 2020. Based on subsequent licensee troubleshooting, the oil leak rate was determined to be approximately 1.14 gallons per day while in operation. The last time NSCW fan ‘4’ ran was on September 6th, which was the same day that the oil level in the gearbox would have dropped below the required level. The cause of the leaking gearbox was due to the failed seal. The gearbox was repaired and NSCW fan ‘4’ was returned to operable status on November 4th. Therefore, the NSCW fan ‘4’ was inoperable according to TS for approximately 60 days (September 6th through November 4th). A search of LERs did not yield any windowed events. A review of the preliminary SDP evaluation indicates that the risk of this condition will not exceed the ASP Program threshold and, therefore, is not a precursor.</td></tr>
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Plant	LER	Event Date	Event Description	LER Date	Screen Date	ASP Criterion	Completion Date	Classification
Callaway	483-20-007	11/2/20	“B” Pressurizer PORV Inoperable Due to Nonconformance with EQ Requirements	12/31/20	2/3/21	3i	3/9/21	Analyst Screen-Out
Analyst Justification. This condition is not discussed in any IR to date; the LER remains open. While performing refueling outage maintenance activities on November 2, 2020, pressurizer power-operated relief valve (PORV) ‘B’ was determined to not meet the requirements of the Environmental Qualification Program. Specifically, a CONAX mid-lock ferrule on the valve operator power cabling was not crimped to the feed-through sheath. The CONAX body, mid-lock ferrule, and feed-though sheath provide the environmental qualification seal when the ferrule is crimped to the sheath. A licensee evaluation could not determine when this degradation occurred but concluded that it likely existed for a long period of time, and possibly since initial plant startup. The cause for the improper connection seal was that the mid-lock was not torqued correctly. The CONAX connector for PORV ‘B’ was re-terminated and torqued to the manufacturer’s specified value to ensure a proper seal for the valve operator. An inspection of the PORV ‘A’ mid-lock revealed a proper configuration. The pressurizer PORVs are credited to mitigate accident sequences that could result in adverse containment environments such as a main steam line break (MSLB) where moisture intrusion could result in short-circuit that could prevent the solenoid coil from energizing to open the PORV. A search of LERs did not yield any windowed events. A licensee evaluation determined that a postulated MSLB with the dependent failure of PORV ‘B’ and the random failure of PORV ‘A’ would result in a delay of RCS depressurization and entry into SDC. There is potential that this condition could also affect the long-term availability of the feed and bleed cooling, but it is believed that this lower-energy event would likely not affect PORV ‘B’. Although the potential increase in risk associated with this condition cannot be readily quantified using the existing Callaway SPAR model, the qualitative considerations indicate that this condition is not expected to significantly increase the risk of core damage. Therefore, this condition is determined to be below the ASP Program threshold and, therefore, is not a precursor.								
Brunswick 1	325-20-002	3/24/20	Technical Specification Required Shutdown due to Unidentified Leakage	11/17/20	2/18/21	3i	3/15/21	Analyst Screen-Out
Analyst Justification. This condition is not discussed in any IR to date; the LER remains open. On March 24, 2020, during startup testing, operators attempted to open main steam SRV ‘1F’ from the MCR. Tailpipe temperature trends indicated that the pilot valve opened, but that the main disc failed to properly reposition to complete the cycle. The pilot valve remained open and passed steam via the tailpipe to the suppression pool. During troubleshooting and other startup testing, MCR operators received unexpected indication of 1.6 gpm unidentified leakage in the drywell. In approximately 1 hour, this leakage increased to 3.75 gpm, which exceeded the TS limit of 2 gpm change in unidentified leakage within 24 hours. As a result, operators commenced the required TS shutdown. The cause of this intermediate-position failure of SRV ‘1F’ was determined to be susceptibility of the Target Rock two-stage design to fretting wear of the main disc stem to piston connection when the associated main body is subjected to a high number of cycles during testing, resulting in displacement of the piston and galling in the main body piston guide. NRC inspectors determined that the pilot valve replacement completed in the most recent refueling outage (March 2020) resulted in the misalignment of the main valve and the subsequent failure of the SRV to open. A search of LERs did not yield any windowed events. A risk assessment performed assuming SRV ‘1F’ was stuck closed for the bounding exposure time of 1 week results in a negligible ΔCDP from internal events, seismic hazards, and high winds (including hurricanes and tornadoes). The lack of internal fire and flood scenarios in the Brunswick SPAR model is an uncertainty; however, these hazards are not expected to result in a significant risk impact due to the short exposure time and large number of total SRVs (11) available for both ADS and pressure relief function. This analysis result is below the ASP Program threshold and, therefore, this condition is not a precursor.								

Plant	LER	Event Date	Event Description	LER Date	Screen Date	ASP Criterion	Completion Date	Classification
Palisades	255-20-001	7/27/20	Service Water System Inoperable for Longer than Allowed by Technical Specifications	9/25/20	10/28/20	3c	3/16/21	SDP Screen-Out
Analyst Justification. A preliminary SDP risk assessment has been completed; the final evaluation will be documented in the forthcoming quarterly IR. On July 27, 2020, operators attempted to throttle open CV-0826, the component cooling water (CCW) heat exchanger E-54B service water outlet valve. During this evolution, the MCR position indication for the CV-0826 actuator indicated fully open; however, the valve did not open. Subsequent troubleshooting revealed that the Bettis operating pin was incorrectly installed allowing the valve actuator coupling to become disengaged from the valve stem. This valve failure resulted in its associated train of service water to be inoperable according to TS. CV-0826 operability was restored by operators placing the pin in the correct position and reengaging the actuator coupling on July 28th. The affected service water train was declared operable following successful testing. Maintenance was performed during the previous refueling outage in November 2018. From November 9, 2018, to May 27, 2020, surveillance testing results showed that the Bettis actuator was coupled. Therefore, the licensee determined that the actuator coupling for CV-0826 was disengaged from the valve stem from May 27th through July 27th (approximately 62 days). A search of LERs did not reveal any windowed events. A review of the preliminary SDP risk assessment indicates that the risk of this condition will not exceed the ASP Program threshold and, therefore, is not a precursor.								