This report provides the results the Accident Sequence Precursor Program for 2022. In addition, trends and key insights are provided for the past 10 years (2013 through 2022).

U.S. Nuclear Regulatory Commission Accident Sequence Precursor Program 2022 Annual Report

April 2023

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1. 2022 ASP RESULTS

There were 135 licensee event reports (LERs) issued in calendar year 2022. From these LERs, 111 (82%) were screened out in the initial screening process and 24 events were selected and analyzed as potential precursors. The overall number of LERs and potential precursors continues to decrease to historical lows. Figure 1 provides a breakdown of the number of LERs reviewed by the Accident Sequence Precursor (ASP) Program since the switch was made to review LERs issued on a calendar-year basis in 2016.

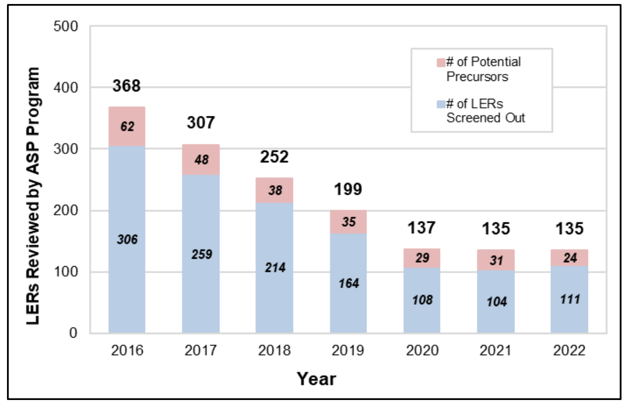

Figure 1. Breakdown of LERs Reviewed by ASP Program Since 2016

Of the 24 potential precursors, 8 events were determined to exceed the ASP Program threshold and, therefore, are precursors. An additional two precursors were identified for a degraded condition where no LER was issued. Of the 10 total precursors identified in 2022, an independent ASP analysis was performed to determine the risk significance for 4 of these events, while 6 precursors were the result of greater-than-*Green* inspection findings.[1] Table 1 provides a brief description of all precursors identified in 2022. The four precursors identified in 2022 using an independent ASP analysis were compared with results from Management Directive (MD) 8.3, "NRC Incident Investigation Program," (ML18073A200) and Significance Determination Process (SDP). This comparison is provided in Appendix A.

Table 1. 2022 Precursors

Plant/Description	LER/IR	Event Date	Exposure Time	CCDP/ ΔCDP
Quad Cities 1, High-Pressure Coolant Injection (HPCI) System Inoperable due to Gland Seal System Malfunction (ML23087A086)[2]	254-22-001	12/1/21	55 days	$\geq 1\times10^{-6}$
Summer, Potential Condition Prohibited by Technical Specifications (TS): Inoperable 'B' Emergency Diesel Generator (EDG) (ML22287A184)	395-22-002	2/9/22	26 days	*White* Finding
Calvert Cliffs 1, Failure to Properly Implement Foreign Material Exclusion Practices Results in EDG Failure (ML22314A100)	05000317/2022003 *(No LER issued)*	2/19/22	161 days	*White* Finding
Calvert Cliffs 2, Failure to Properly Implement Foreign Material Exclusion Practices Results in EDG Failure (ML22314A100)[3]	05000318/2022003 *(No LER issued)*	2/19/22	179 days	5×10^{-6}

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1 Two additional greater-than-*Green* inspection findings were identified in 2022. A *White* emergency preparedness finding was identified for Waterford Steam Electric Station (ML22241A143). This finding was not associated with increased risk to core damage and, therefore, is out of the scope of the ASP Program. A *White* finding associated with a Unit 2 reactor trip and loss of condenser heat sink was identified for Peach Bottom Atomic Station (ML22314A098). Since a reactor trip occurred, an independent ASP analysis was performed, which determined that the risk associated with this event was below the ASP Program threshold and, therefore, the event was not a precursor. Additional information regarding this evaluation is provided in Appendix B.

2 This precursor occurred in 2021 and, therefore, is considered a 2021 precursor for trending purposes.

3 The *White* finding associated with this condition only applies to Unit 1. However, the SDP risk evaluation included an analysis of the risk impact to Unit 2, which was accepted as the ASP analysis result.

Plant/Description	LER/IR	Event Date	Exposure Time	CCDP/ ΔCDP
Quad Cities 2, Electromatic Relief Valve '3B' Did Not Actuate Due to Incorrectly Oriented Plunger Well Plastic Guides (ML22313A150)	265-22-001	3/21/22	1 year	*White* Finding
River Bend, Division '1' EDG Speed Sensor Power Supply Failure (ML23041A001)	458-22-003	7/4/22	30 days	1×10^{-5}
Browns Ferry, HPCI System Declared Inoperable Due to a Corroded Actuator (ML23048A062)	259-22-002	7/12/22	48 days	*White* Finding[4]
Sequoyah 1, Failure of 1B-B Centrifugal Charging Pump Results in Condition Prohibited by TS (ML23104A013)	327-22-001	7/25/22	139 hours	2×10^{-6}
Surry 1, Failure of EDG Results in Operation or Condition Prohibited by TS (ML23054A003)	280-22-002	7/25/22	24 days	3×10^{-5}
River Bend, High-Pressure Core Spray (HPCS) Inoperable Due to Transformer Failure	458-22-004	9/19/22	26 days	**TBD**[5]

After further analysis, the remaining 16 LERs identified by the initial LER screening were determined not to be precursors. Additional information on the LERs determined not to be precursors via an ASP analysis or by acceptance of SDP results is provided in Appendix B.

2. ASP TRENDS

Trend analyses were performed for the past decade (2013–2022) on the occurrence rate of all precursors and other precursor groups.

Table 2. Precursor Trend Results

Precursor Group	Trend	p-value
All Precursors	Decreasing	0.0009
Important Precursors (i.e., CCDP/ΔCDP $\geq 10^{-4}$)	No Trend	0.1
Precursors with CCDP/ΔCDP $\geq 10^{-5}$	Decreasing	0.03
Initiating Events (IEs)	Decreasing	0.0008
Degraded Conditions (DCs)	No Trend	0.08
LOOPs	Decreasing	0.03
EDG Failures	No Trend	0.7
Boiling-Water Reactor (BWR) Precursors	No Trend	0.06
Pressurized-Water Reactor (PWR) Precursors	Decreasing	0.005

Figure 2 provides the occurrence rate and trend of all precursors for the past decade. Additional precursor trends are provided in the Figures 3–5.

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4 Although the final notice of violation has not been issued for this *White* finding yet, the licensee does not contest the violation nor the NRC's assessment of its significance (ML23101A025).

5 The evaluation of a potential licensee performance deficiency associated with this degraded condition is ongoing. However, initial evaluations indicate that the risk of this condition will likely exceed the precursor threshold.

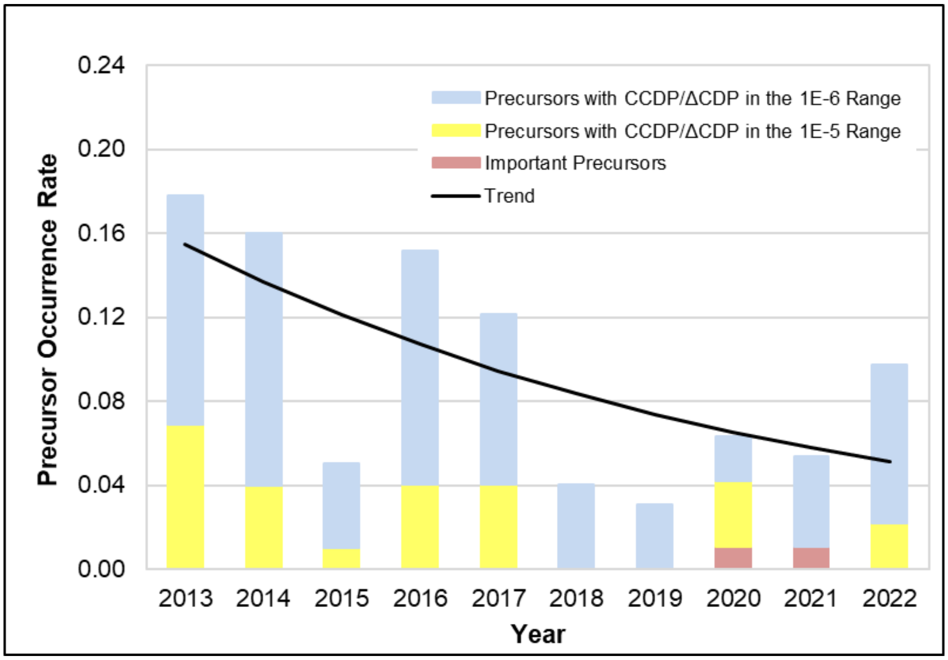

Figure 2. Occurrence Rate of All Precursors

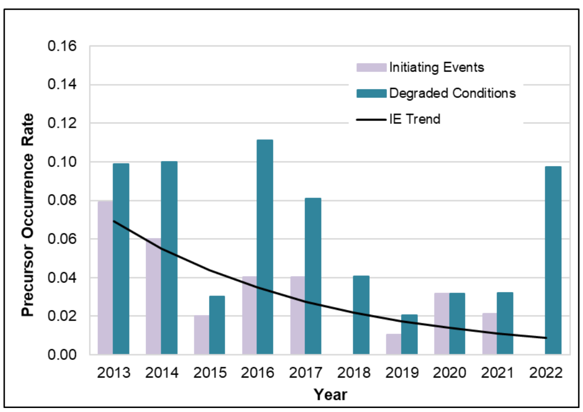

Figure 3. Occurrence Rates of IE / DC Precursors

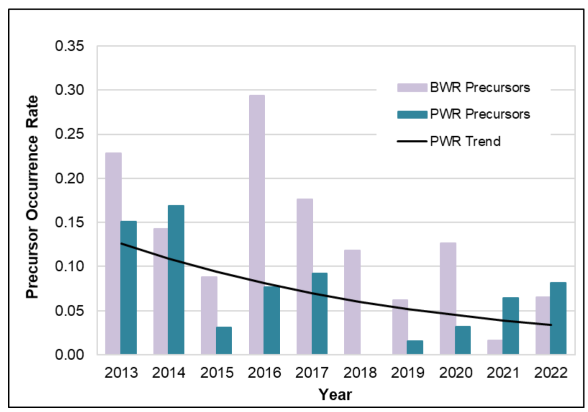

Figure 5. Occurrence Rates of BWR / PWR Precursors

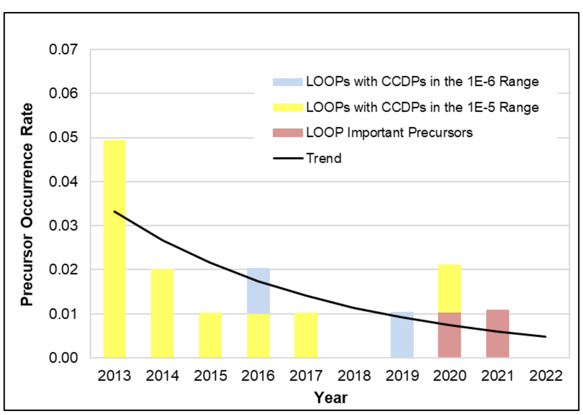

Figure 4. Occurrence Rate of LOOP Precursors

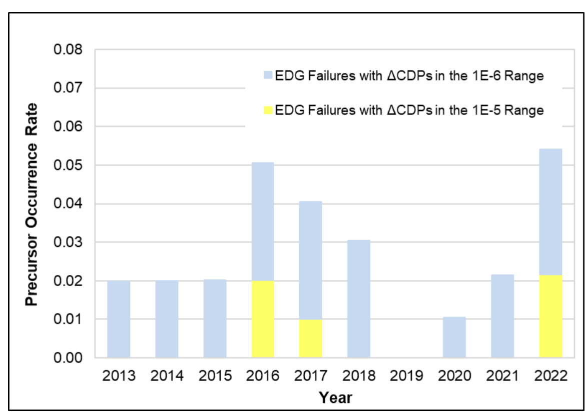

Figure 6. Occurrence Rates of EDG Precursors

3. KEY INSIGHTS

This section provides a few key insights based on the review of the 93 precursors that were identified in the past decade (2013–2022). Note that additional insights can be gathered by using the publicly available [ASP Program Dashboard](). There were two important precursors identified during this period, both of which of were due to LOOPs.

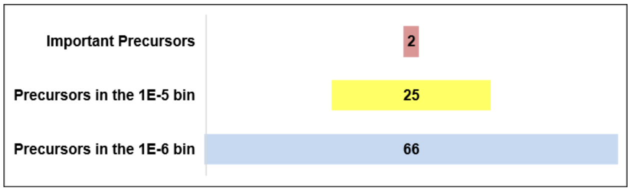

Figure 7. Precursor Breakdown by Risk Bin

The ratio of precursors identified via greater-than-*Green* vs. independent ASP evaluations continues to decrease. In 2016, the 10-year percentage was 69%, but is now 53%.

The most frequent IEs that resulted in precursors were LOOPs and losses of a condenser heat sink.

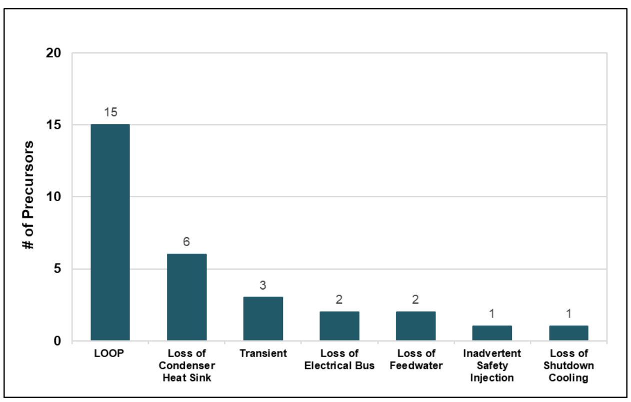

Figure 8. Most Frequent IE Precursor Types

Natural phenomena caused 11 precursors, with snow/ice and lightning the most frequent causes.

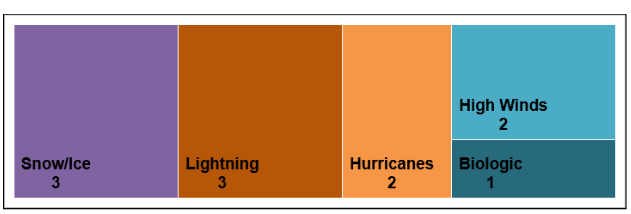

Figure 9. Most Frequent Precursor SSC Failures

The most frequent structure, system, and component (SSC) failures observed in precursors were associated with EDGs, flood protection, and switchyard.

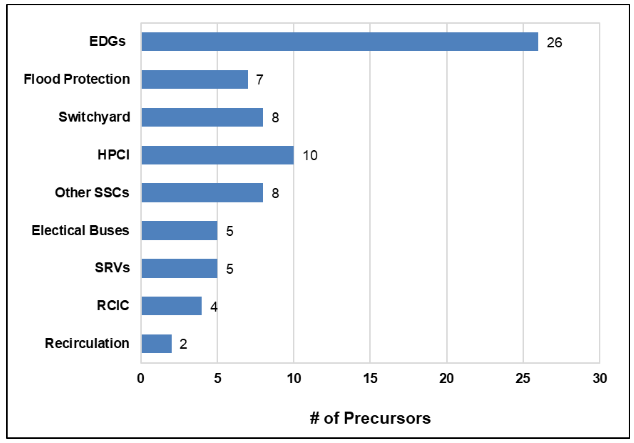

Figure 10. Most Frequent Precursor SSC Failures

A review of the precursors associated with inspection findings that had a significant impact on the risk of the event were most likely due to inadequate procedures or design issues.

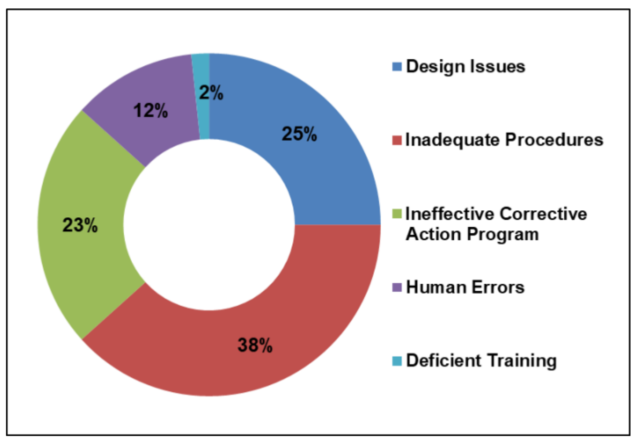

Figure 11. Dominant Precursor SSC Failures

4. ASP INDEX

The ASP index shows the cumulative plant average risk from precursors on an annual basis. Unlike the trend analyses performed on various precursor groups that are focused on the occurrence rate of precursors, the ASP index is focused on the total risk due to all precursors. Therefore, the ASP index provides a unique way to evaluate the risk of longer-term DCs over the entire duration of the condition.

The ASP index (shown in Figure 11) does not exhibit a statistically significant trend (*p-value* = 0.97) for the past decade (2013–2022). The total risk associated with precursors (93 total precursors) is dominated by the 2 important precursors, which account for approximately 53% of the total risk due to all precursors. The other 91 precursors account for approximately 47% to the total risk due to all precursors.

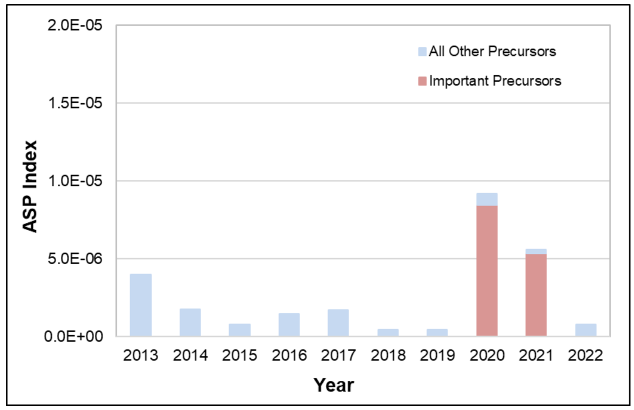

Figure 12. ASP Index

A description of how the ASP index is calculated is provided in past annual reports, which can be accessed from the [ASP Program Public Webpage].

5. OBSERVATIONS

A review of the ASP Program data and trends for the past decade (2013–2022) supports the following observations:

- Although the number of precursors identified in 2022 is the highest total in the past 5 years, this increase has not affected the decreasing 10-year trend in the occurrence rate of all precursors. In addition, the number of LERs and potential precursors identified remain at historical low values.
- Current agency oversight programs and licensing activities remain effective.
- 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.

Appendix A: Comparison of 2022 ASP Analyses

The four precursors identified in 2022 using an independent ASP analysis were compared with results from MD 8.3 and SDP analyses, as shown in the following table. Given the three programs have different functions, it is expected that the results are likely to be different.

Event Description	Program Results	SPAR Model/Methodology Improvements and Insights
Quad Cities 1, LER 254-22-001, HPCI System Inoperable due to Gland Seal System Malfunction	**MD 8.3.** No evaluation performed. **SDP.** Two Green findings (i.e., very low safety significance) were identified associated with this condition. However, neither licensee performance deficiencies directly resulted in the HPCI failure and, therefore, no detailed risk evaluation was performed. See IR 05000254/2022001 (ML22130A771) for additional information. **ASP.** $\Delta CDP \geq 1\times10^{-6}$; HPCI unavailable for 55 days. See final ASP analysis (ML23087A086) for additional information.	Identified issue associated with a calculated negative ΔCDP for some SPAR model sequences calculated in SAPHIRE. Interim solution was implemented in the final calculation. Qualitative fire evaluation performed because internal fires are not included in the Quad Cities SPAR model. This is the first time a precursor has been identified largely based on a qualitative evaluation for hazards.
***River Bend,* LER 458-22-003,** Division ‘1’ EDG Speed Sensor Power Supply Failure	**MD 8.3.** No evaluation performed. **SDP.** No performance deficiency was identified for this event; therefore, no SDP evaluation was performed. **ASP.** $\Delta CDP = 1\times10^{-5}$; EDG unavailable for 30 days. See final ASP analysis (ML23041A001) for additional information.	Credit for FLEX mitigation strategies was provided using with updated reliability data provided by the PWROG. Modified FLEX modeling according to review of licensee’s final integrated plan.
Sequoyah 1, LER 327-22-001, Failure of 1B-B Centrifugal Charging Pump Results in Condition Prohibited by TS	**MD 8.3.** No evaluation performed. **SDP.** No performance deficiency was identified for this event; therefore, no SDP evaluation was performed. **ASP.** $\Delta CDP = 2\times10^{-6}$; centrifugal charging pump unavailable for 139 hours. See final ASP analysis (ML23104A013) for additional information.	Identified and corrected an error associated with component cooling water dependency for the safety injection and low-pressure injection pumps in the Sequoyah base SPAR model.
Surry 1, LER 280-22-002, Failure of EDG Results in Operation or Condition Prohibited by TS	**MD 8.3.** No evaluation performed. **SDP.** A Green finding (i.e., very low safety significance) was identified associated with this condition. However, the licensee performance deficiency was associated with an inadequate cause evaluation and, therefore, no detailed risk evaluation was performed. See IR 05000280/2022004 (ML23041A023) for additional information. **ASP.** $\Delta CDP = 3\times10^{-5}$; EDG unavailable for 24 days. See final ASP analysis (ML23054A003) for additional information.	Credit for FLEX mitigation strategies was provided using with updated reliability data provided by the PWROG. Modified FLEX modeling according to review of licensee’s final integrated plan. Identified and corrected an overly conservative assumption in the base Surry SPAR model change that auxiliary feedwater would be unavailable during main control abandonment scenarios.

Appendix B: 2022 ASP Program Screened Analyses

The table in this appendix provides the justification for each LER that was screened out of the ASP Program based on a simplified or bounding analysis or by acceptance of 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.

<table>
<tr><th>Plant</th><th>LER</th><th>Event Date</th><th>Description</th><th>LER Date</th><th>Screen Date</th><th>Criterion</th><th>Date Assigned</th><th>Date Completed</th><th>Classification</th></tr>
<tr><td>FitzPatrick</td><td>333-21-002</td><td>11/18/21</td><td>Automatic HPCI System Function Prevented by Control Circuit Relay Failure</td><td>1/14/22</td><td>2/3/22</td><td>3a</td><td>2/7/22</td><td>4/14/22</td><td>Analyst Screen-out</td></tr>
<tr><td colspan="10">Analyst Justification. This condition is not discussed in any inspection report (IR) to date, the licensee event report (LER) remains open. On November 18, 2021, during a simulated actuation test of high-pressure coolant injection (HPCI) system, the pump discharge valve 23MOV-19 failed to open. The licensee determined that the valve failed to open due to its control logic relay. Specifically, the relay contacts failed to close due to binding within the contact carrier channel caused by chaffing. The relay was replaced and HPCI system was restored to operable status on November 19, 2021. The maximum exposure time that 23MOV-19 would have failed to automatically open during a postulated low reactor water level condition was 1 day. And although the valve would not have automatically opened, operators had the ability to manually open the valve. A search of LERs did not yield any windowed events. Because the licensee restored HPCI within their technical specification (TS) required action time (14 days) and the exposure time was not longer than the TS allowed outage time for the system, the risk is expected to be low and, therefore, this condition is not a precursor. To gather additional risk insights, an evaluation was performed assuming the unavailability of HPCI for the maximum exposure time of 1 day, which resulted in a mean increase in core damage probability (ΔCDP) of 3E-8 from internal events, high winds (including tornadoes), and seismic events. Internal flooding and fires scenarios are not included in the FitzPatrick SPAR model; however, it is not expected that the risk impact from these hazards would result in any new insights.</td></tr>
<tr><td>FitzPatrick</td><td>333-22-001</td><td>4/29/22</td><td>Exhaust Drain Pot Line Filled with Water up to HPCI Turbine due to Relay Failure</td><td>6/28/22</td><td>7/7/22</td><td>3i</td><td>7/21/22</td><td>7/28/22</td><td>Analyst Screen-out</td></tr>
<tr><td colspan="10">Analyst Justification. This condition is not discussed in any IR to date, the LER remains open. On April 28, 2022, the HPCI drain pot water level alarm was received in the main control room (MCR). Subsequent licensee troubleshooting determined that a HPCI logic relay failed to activate the HPCI gland seal condensate pump to remove condensate from the turbine exhaust. As a result, water from steam leakage had accumulated in the HPCI turbine casing. HPCI was declared operable after the turbine casing was drained and failed relay was repaired. The maximum exposure time of the HPCI system being compromised was 14 hours. A search of LERs did not yield any windowed events. Because the licensee restored HPCI within their TS required action time (14 days) and the exposure time was not longer than the TS allowed outage time for the system, the risk is expected to be low, and, therefore, this condition is not a precursor. To gather additional risk insights, an evaluation was performed assuming the unavailability of HPCI for the maximum exposure time of 14 hours, which resulted in a mean ΔCDP of 2E-8 from internal events, high winds (including tornadoes), and seismic events. Internal flooding and fires scenarios are not included in the FitzPatrick SPAR model; however, it is not expected that the risk impact from these hazards would result in this condition exceeding the precursor threshold given the short exposure time.</td></tr>
<tr><td>Fermi</td><td>341-22-002</td><td>5/11/22</td><td>Unexpected HPCI Turbine Trip</td><td>7/6/22</td><td>7/7/22</td><td>3i</td><td>7/21/22</td><td>7/29/22</td><td>Analyst Screen-out</td></tr>
<tr><td colspan="10">Analyst Justification. This condition is not discussed in any IR to date, the LER remains open. On May 11, 2022, the HPCI turbine unexpectedly experienced an overspeed trip during performance of a surveillance test during startup. Subsequent licensee troubleshooting identified the cause was the HPCI turbine magnetic pick-up speed element was shorted, which broke the speed feedback circuit to the HPCI speed controller. Troubleshooting also identified that the HPCI pump discharge pressure switch, which controls the HPCI minimum flow valve, was found to be out of tolerance low resulting in the minimum flow valve to cycle open and closed. There was no evidence that either condition existed prior to the overspeed trip event on May 11th. This conclusion was based on the HPCI system performing as expected during surveillance testing on May 9th and that the HPCI system did not exhibit abnormal behavior prior to the start on the test on May 11th. The element was replaced on May 12th and the testing was completed satisfactorily on May 16th. The HPCI pump discharge pressure switch was successfully calibrated into tolerance on May 16th. A search of LERs did not yield any windowed events. Because the licensee restored HPCI within their TS required action time (14 days) and the exposure time was not longer than the TS allowed outage time for the system, the risk is expected to be low and, therefore, this condition is not a precursor. To gather additional risk insights, an evaluation was performed assuming the unavailability of HPCI for the maximum exposure time of 8 days, which resulted in a mean ΔCDP of 2E-7 from internal events, internal fires, internal floods, high winds (including tornadoes), and seismic events.</td></tr>
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<table>
<tr><th>Plant</th><th>LER</th><th>Event Date</th><th>Description</th><th>LER Date</th><th>Screen Date</th><th>Criterion</th><th>Date Assigned</th><th>Date Completed</th><th>Classification</th></tr>
<tr><td>Shearon Harris</td><td>400-22-004</td><td>5/2/22</td><td>Both Trains of High Head Safety Injection Inoperable</td><td>6/30/22</td><td>7/19/22</td><td>3i</td><td>7/21/22</td><td>8/5/22</td><td>Analyst Screen-out</td></tr>
<tr><td colspan="10">Analyst Justification. This condition is not discussed in any IR to date, the LER remains open. On May 2, 2022, the licensee was performing testing of the chemical volume control system (CVCS)/safety injection (SI) system, which required the closing of the charging SI pump discharge cross-connect valve. MCR operators immediately received reactor coolant pump (RCP) seal injection low flow alarm with seal injection flow indicating to be lowering to zero. Operators immediately reopened the charging SI pump discharge cross-connect valve, and seal injection flow recovered to normal within approximately 23 seconds. Subsequent licensee investigation identified that the charging SI pump ‘B’ discharge valve was locked closed from maintenance completed on April 28, 2022. The post-maintenance system realignment was disrupted by a reactor trip that occurred on April 29th and licensee failed to reopen the charging SI pump ‘B’ discharge valve in accordance with procedures. With both the discharge and cross-connect valves closed, both trains of the high-head SI were inoperable. A search of LERs revealed LER 400-22-003, which reported a loss of condenser heat sink initiating event that occurred on April 29th, while the charging SI pump ‘B’ discharge valve locked closed. Therefore, there are three potential risk impacts associated with these LERs: (a.) the very short time that both the charging SI pump discharge cross-connect valve and SI pump ‘B’ discharge valve were both closed, (b.) the loss of condenser heat sink transient with the closed SI pump ‘B’ discharge valve, and (c.) the 9-day period (approximate) that the SI pump ‘B’ discharge valve was closed. Both valves were closed for less than a minute and, therefore, the risk impact was negligible. A risk assessment showed the impact of the loss of condenser heat sink with the closed SI pump ‘B’ discharge valve was negligible when compared to the nominal conditional core damage probability (CCDP) of a loss of condenser heat sink transient. The plant’s TS allow one charging SI pump to be inoperable indefinitely and, therefore, the risk impact associated the closed SI pump ‘B’ discharge valve is expected to be low. To gather additional risk insights, an evaluation was performed assuming the unavailability of SI train ‘B’ for the 9-day exposure time, which resulted in a mean ΔCDP of 1E-7 from internal events, internal fires, internal floods, high winds (including tornadoes), and seismic events. Given these considerations, the risk associated with this degraded condition is judged to be below the ASP Program threshold and, therefore, is not a precursor.</td></tr>
<tr><td>D.C. Cook 1</td><td>315-22-001</td><td>5/24/22</td><td>Manual Reactor Trip Following Manual Turbine Trip due to High Vibrations on Main Turbine</td><td>7/21/22</td><td>8/22/22</td><td>2h</td><td>8/23/22</td><td>9/20/22</td><td>Analyst Screen-out</td></tr>
<tr><td colspan="10">Analyst Justification. This event is not discussed in any IR to date, the LER remains open. On May 24, 2022, while emerging from the most recent refueling outage, the main turbine experienced high vibrations while being rolled and was subsequently manually tripped by operators. Following the main turbine trip, the high vibrations persisted and, therefore, operators manually tripped the reactor and closed the MSIVs to break condenser vacuum. Due to the significant amount of maintenance done on the main turbine during the refueling outage, the potential for turbine issues that could result in turbine or reactor trip was anticipated as part of the startup preparations. All control rods fully inserted. The auxiliary feedwater (AFW) pumps started as required and supplied inventory makeup to the steam generators (SGs). During the event, reactor coolant system (RCS) temperature initially lowered as expected and was stabilized at approximately 550°F by the SG power-operated relief valves (PORVs). A preliminary licensee analysis has determined the cause of the turbine vibrations to be a rub on the high-pressure turbine shaft seals. A search of LERs did not yield any windowed events. The risk of this event is bounded by a non-recoverable loss of condenser heat sink and, therefore, the risk of this event is below the ASP Program threshold and is not a precursor.</td></tr>
<tr><td>Quad Cities 1</td><td>254-22-002</td><td>5/10/22</td><td>LPCI Manually Isolated Due to Valve Test Equipment Issue</td><td>7/8/22</td><td>8/22/22</td><td>3d</td><td>8/23/22</td><td>10/18/22</td><td>Analyst Screen-out</td></tr>
<tr><td colspan="10">Analyst Justification. A minor violation associated with this condition was identified in IR 05000254/2022002 (ML22221A202); the LER is closed. On May 10, 2022, the low-pressure coolant injection (LPCI) loop ‘1B’ upstream stop valve failed its thrust test. The valve was subsequently declared inoperable. TS 3.6.1.3, Condition A requires that the affected primary containment isolation flow path be isolated within 4 hours. Operators de-activated the affected penetration by closing the LPCI loop ‘1B’ downstream stop valve, and electrically isolating it by opening its breaker. The licensee investigation concluded that there was no actual valve thrust deficiency. It was determined that the measurement and test equipment sensor was not bonded correctly to the valve stem. A new sensor was installed, and the valve was tested successfully. The LPCI loop ‘1B’ was isolated for 21 hours and 14 minutes. A review of LERs did not reveal any windowed events. Although LPCI loop ‘1A’ remained available throughout, a loss-of-coolant accident (LOCA) on recirculation loop ‘A’ would have resulted in a loss of all LPCI function. Therefore, a risk analysis that conservatively assumed both LPCI injection loops were failed for 22 hours was performed. This calculation resulted in a mean ΔCDP of 2E-9 from internal events, internal floods, high winds (including tornadoes), and seismic events. Internal fires scenarios are not included in the Quad Cities SPAR model; however, it is not expected that the risk impact from this hazard would result in this condition exceeding the precursor threshold given the short exposure time and the risk likely being dominated by a LOCA on recirculation loop ‘A’. The risk associated with this degraded condition is judged to be below the ASP Program threshold and, therefore, is not a precursor.</td></tr>
<tr><td>Dresden 2</td><td>237-22-002</td><td>7/29/22</td><td>Ultimate Heat Sink Declared Inoperable due to River Grass Accumulation</td><td>9/27/22</td><td>10/21/22</td><td>3f</td><td>10/24/22</td><td>11/1/22</td><td>Analyst Screen-Out</td></tr>
<tr><td colspan="10">Analyst Justification. This condition is not discussed in any IR to date, the LER remains open. On July 29, 2022, an equipment operator identified the intake suction bay ‘13’ water level was less than required by TS (at least 501.5 feet mean sea level). The plant entered TS 3.7.3, “Ultimate Heat Sink”, Condition A. The licensee cleared river vegetation and grass from the intake bar racks, troughs and traveling screens. Approximately 3.5 hours later, bay ‘13’ water level was restored and TS 3. 7.3, Condition A was exited on July 30th. Approximately 10 hours later, accumulation of river vegetation and grass occurred again and, therefore, TS 3.7.3 Condition A, was reentered due to low water level in bay ‘13’. The licensee cleared the debris, operators secured a circulating water pump, and transitioned the plant to closed cycle to restore intake suction bay ‘13’ water level. Bay ‘13’ water level was restored and TS 3.7.3, Condition A was exited in approximately 7 hours. A review of LERs did not reveal any windowed events. Because the licensee restored the bay ‘13’ level, and therefore, their UHS within the TS required action time (12 hours) and the exposure time was not longer than the TS allowed outage time for the system, the risk is expected to be low and, therefore, this condition is not a precursor.</td></tr>
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Plant	LER	Event Date	Description	LER Date	Screen Date	Criterion	Date Assigned	Date Completed	Classification
Brunswick 1	325-22-001	7/15/22	HPCI Inoperable	9/12/22	9/30/22	3d	10/4/22	**11/28/22**	Analyst Screen-Out
Analyst Justification. This condition is not discussed in any IR to date, the LER remains open. On July 15, 2022, the HPCI system was declared inoperable upon discovering the HPCI flow controller without power during MCR operator control board walkdowns. An initial licensee investigation identified a loose lead to the HPCI flow controller. Power was returned to the HPCI flow controller after personnel tightened the lead later on July 15th. Additional troubleshooting determined that the identified loose lead could not have caused loss of power to the HPCI flow controller device and that some other intermittent connection was present. While performing a calibration check on the device, a loose fuse holder connection was also identified on the backside of the flow controller. The fuse was secured in the use holder and HPCI was declared operable on July 16th following post-maintenance testing. A review of LERs did not reveal any windowed events. Discussions with NRC inspectors revealed a maximum exposure time of 24 hours plus repair time (approximately 16 hours). A risk analysis assuming HPCI was failed for 40 hours resulted in a mean ΔCDP of 4E-7 from internal events, internal fires, internal floods, high winds (including hurricanes and tornadoes), and seismic events. The risk associated with this degraded condition is below the ASP Program threshold and, therefore, is not a precursor.									
Perry	440-22-001	6/24/22	LPCS Inoperable due to Loss of Minimum Flow Valve	8/17/22	9/30/22	3d	10/4/22	**12/2/22**	Analyst Screen-Out
Analyst Justification. This condition is not discussed in any IR to date, the LER remains open. On June 24, 2022, licensee personnel observed that the low-pressure core spray (LPCS) minimum flow valve experienced a loss of position indication while stroking closed during quarterly surveillance testing. A subsequent licensee investigation revealed that two of three main-line power fuses in the motor control center (MCC) disconnect for the LPCS minimum flow valve were blown. In addition, examination of the LPCS minimum flow valve revealed that the motor-operated actuator had become separated from the valve due to broken mounting bolts. This resulted in the LPCS system being declared inoperable. New actuator to valve bolts, a new actuator motor, and new disconnect fuses were installed for the LPCS minimum flow valve and the system was restored on June 27th after successful completion of post-maintenance testing. A review of LERs did not reveal any windowed events. A risk analysis assuming LPCS was failed for 3 months resulted in a mean ΔCDP of 1E-7 from internal events, internal floods, high winds (including tornadoes), and seismic events. This estimate is believed to be conservative because the failure of the minimum flow valve would not affect LPCS during a large LOCA, which is the dominant internal event risk contributor. Internal flooding and fires scenarios are not included in the Perry SPAR model. The risk impact due to internal floods and fires is likely to be minimal for this degraded condition because these hazards are unlikely to result in a LLOCA for which LPCI or LPCS are required to prevent core damage. For other initiating events, multiple sources of low-pressure availability mitigate the risk associated with a LPCS unavailability. Therefore, the risk associated with this degraded condition is judged to be below the ASP Program threshold and, therefore, is not a precursor.									
Peach Bottom 2	277-22-001	5/16/22	Automatic Reactor Scram due to Loss of Power to Both RPS Buses	7/15/22	8/22/22	2h	8/23/22	**12/5/22**	Analyst Screen-Out
Analyst Justification. A White finding was identified in IR 05000277/2022090 (ML22314A098); the LER is closed. On May 16, 2022, an electrical grid transient resulted in main generator perturbation and MCR alarms and decreasing recirculation pump speeds in both units. In addition, the Unit 2 reactor water cleanup (RWCU) system also tripped. Approximately 5 minutes later, another grid transient occurred with a large main generator perturbation, which resulted in the output breaker of the '2A' reactor protection system (RPS) motor generator set output breaker to trip and subsequent loss of power to the '2A' RPS bus, a half scram, and Unit 2 primary containment isolation system (PCIS) group II/III inboard isolations. Plant procedures directed operators to restore the '2A' RPS motor generator set to service. However, operators incorrectly opened the breakers from the alternate electrical feed to the '2B' RPS bus, which resulted in a reactor Unit 2 scram and PCIS group I isolation including the closure of all main steam isolation valves (MSIVs). Safety relief valves initially lifted within their setpoints to control pressure, then the valves were utilized manually for pressure control. Reactor core isolation cooling (RCIC) was manually utilized for reactor pressure vessel level control, while HPCI was manually used pressure control. NRC inspectors determined that the licensee failure to meet the requirement of 10 CFR Part 50, Appendix B, Criterion V, to accomplish an activity affecting quality using a procedure appropriate to the circumstances was a performance deficiency. A search of LERs did not yield any windowed events. A detailed SDP risk evaluation was performed by a Region 1 SRA assuming a nonrecoverable loss of condenser heat sink initiating event due to the closure of MSIVs, which resulted in a ΔCDP of 6E-6 per year for this event. However, given a reactor trip occurred, an independent ASP evaluation was performed in accordance with RIS 2006-024. This evaluation concluded that this event is bounded by a non-recoverable loss of condenser heat sink and, therefore, the risk of this event is below the ASP Program threshold and is not a precursor.									

Plant	LER	Event Date	Description	LER Date	Screen Date	Criterion	Date Assigned	Date Completed	Classification
Beaver Valley 2	412-22-001	7/13/22	Operation or Condition Prohibited by TS and Loss of Safety Function due to EDG Fuel Oil Intrusion into Lube Oil	9/8/22	9/30/22	3e	10/4/22	**1/8/23**	SDP Screen-out
Analyst Justification. A Green finding was identified in IR 0500412/2022003 (ML22314A063); the LER is closed. On July 13, 2022, the licensee identified fuel oil intrusion in the lube oil for EDG '2-2' following a decline in oil viscosity. Initially, the licensee believed there was reasonable assurance that EDG '2-2' remained operable and would be able to fulfil its safety function for its required mission time. An operability determination performed later that day determined that EDG '2-2' would be unable to meet its TS 30-day mission time and was subsequently declared inoperable. Note that the licensee determined that EDG '2-2' would be able to fulfil its PRA mission time of 24 hours. A subsequent licensee investigation determined that the gravity drain from the fuel oil injection pumps to the underground tank was air bound, which prevented excess fuel oil from the pumps from flowing back to the tank and allowed for intrusion into the lube oil. Three of the pumps were replaced and the gravity drain line was vented. The EDG '2-2' lube oil was changed and the EDG was declared operable on July 16th. NRC inspectors determined that the licensee failure to properly preplan and perform maintenance that could affect the performance of safety-related equipment was a performance deficiency. Specifically, the licensee failed to maintain adequate procedural guidance associated with filling and venting of the EDG '2-2' fuel oil system following planned maintenance. This performance deficiency was determined to be Green (i.e., very low safety significance) using the screening questions provided in Appendix A of Inspection Manual Chapter 0609. 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.									
Limerick 1	352-22-001	10/14/22	HPCI Inoperable Due to Inadvertent Isolation Signal	12/13/22	1/6/23	3d	1/9/23	**1/11/23**	Analyst Screen-Out
Analyst Justification. This condition is not discussed in any IR to date, the LER remains open. On October 14, 2022, a HPCI system surveillance test was conducted on the HPCI turbine exhaust vacuum breakers. The HPCI turbine exhaust line vacuum breaker isolation valves, HV-055-1F093 and HV-055-1F095 must be closed to establish the required test alignment, which renders the HPCI system is inoperable, but available. After the HPCI turbine exhaust line vacuum breaker isolation valves were closed, a division '2' safeguard battery ground alarm was received in the MCR. Approximately 44 minutes later, HPCI division '2' isolation signal was received accompanied by auto closure of the outboard HPCI steam line isolation valve and the inboard HPCI pump suppression pool suction valve. Licensee troubleshooting identified degradation of several of the pin connections within the affected electrical connector resulted in a fault that propagated to the HPCI division 2 isolation reset circuit. The fault within the electrical connector was initiated when the degraded pin connections were energized by closure of the outboard HPCI turbine exhaust line vacuum breaker isolation valve, HV-055-1F093, for the planned surveillance test. The defective electrical connector was removed, and the affected cable spliced in accordance with an approved design change. HPCI was returned to operable status on October 17th. A search of LERs did not yield any windowed events. Because the licensee restored HPCI within their TS required action time (14 days) and the exposure time was not longer than the TS allowed outage time for the system, the risk is expected to be low and, therefore, this condition is not a precursor. To gather additional risk insights, an evaluation was performed assuming the unavailability of HPCI for the maximum exposure time of 3 days, which resulted in a mean ΔCDP of 2E-7 from internal events, internal fires, internal floods, high winds (including hurricanes and tornadoes), and seismic events. Note that this estimate is likely conservative due no credit being provided for FLEX mitigation strategies.									
Farley 1	348-22-001	8/3/22	Outdated Relay Settings Resulted in an Automatic Reactor Trip After a Floor Tile was Dropped in High Voltage Switch House	9/30/22	11/9/22	2a	11/9/22	**1/11/23**	Analyst Screen-out
Analyst Justification. This event is discussed in Special IR 05000348/2022050 (ML22272A557), the LER remains open. On August 3, 2022, a transmission/distribution service organization technician agitated a relay in the high-voltage switchyard relay house by inadvertently dropping a floor tile resulting in a protection relay actuation. The initial relay actuation ultimately resulted in the automatic opening of eight switchyard circuit breakers and electrical isolation of the 230-kilovolt (kV) bus '1'. The isolation of bus '1' resulted in an automatic main generator and turbine trip and subsequent automatic reactor trip. In addition, the loss of bus '1' resulted in a LOOP to the startup transformer (SUT) '1B', which resulted in a loss of electrical power to 4 kV buses '1B' and '1C' that resulted in a loss of two RCPs and one circulating water pump. A subsequent failure of an automatic fast bus transfer resulted in a loss of electrical power to 4 kV bus '1A', which caused a simultaneous loss of electrical power to the last RCP and circulating water pump. EDG 'B' automatically started and restored electrical power to the 4 kV bus '1G'. Due to the loss of forced circulation flow in RCS and the loss of the condenser as a heat sink, the MCR operators team stabilized the plant using natural circulation and maintained a secondary heat sink for decay heat removal using the AFW system and the SG atmospheric relief valves. Unit 2 was unaffected by this electrical transient. Approximately 20 minutes into the event, operators determined that the turbine-driven AFW pump was no longer required and attempted to shut it down by closing the steam admission valves in accordance with the operating procedure. However, the conditions for an automatic turbine-driven AFW pump restart remained present due to an undervoltage signal on two out of three RCP buses. This signal caused the valves to automatically reopen resulting in an overspeed pump trip. A search of LERs did not yield any windowed events. NRC inspectors identified an apparent violation associated with the turbine-driven pump issues and an unresolved issue associated with reactor trip and partial LOOP. Discussions with Region 2 SRAs indicate that any potential inspection findings are expected to be Green (i.e., very low safety significance). Regardless of any SDP evaluations associated with this even an independent ASP evaluation was performed in accordance with RIS 2006-024 because a reactor trip occurred. This evaluation concluded that this event is bounded by a non-recoverable loss of condenser heat sink and, therefore, the risk of this event is below the ASP Program threshold and is not a precursor.									

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<tr><th>Plant</th><th>LER</th><th>Event Date</th><th>Description</th><th>LER Date</th><th>Screen Date</th><th>Criterion</th><th>Date Assigned</th><th>Date Completed</th><th>Classification</th></tr>
<tr><td>Peach Bottom 2</td><td>277-22-002</td><td>10/17/22</td><td>ADS Safety Relief Valve Actuator Diaphragm Degraded</td><td>12/15/22</td><td>1/6/23</td><td>3i</td><td>1/9/23</td><td>2/1/23</td><td>Analyst Screen-Out</td></tr>
<tr><td colspan="10">Analyst Justification. This condition is not discussed in any IR to date, the LER remains open. On October 17, 2022, and the plant in Mode 4 in the start of a refueling outage, licensee personnel identified a small steady stream of water (approximately 0.2 gpm) leaking from the insulation around the main steam safety relief valve (SRV) ‘71B’. Subsequent investigation revealed that the leakage was from the relief valve pilot filter plug threaded connection. Subsequent vendor testing revealed that the pneumatic operator failed to actuate and air leakage was audible during testing. Disassembly and examination of the pneumatic operator revealed the actuator diaphragm elastomer had embrittled and delaminated, enabling significant leakage that inhibited manual operation of the SRV, including a loss of ADS function. The SRV was replaced during the refueling outage. SRV ‘71B’ was manually cycled successfully during the post-trip response on May 16, 2022. A search of LERs did not yield any windowed events. A risk analysis was performed assuming that the ADS function of SRV ‘71B’ was failed for a maximum exposure time of 154 days, which resulted in a mean ΔCDP of 2E-10 from internal events, internal fires, internal floods, high winds (including hurricanes and tornadoes), and seismic events. The risk associated with this degraded condition is below the ASP Program threshold and, therefore, is not a precursor.</td></tr>
<tr><td>Shearon Harris</td><td>400-22-006</td><td>10/27/22</td><td>Auxiliary Feedwater Pump Inoperability</td><td>12/20/22</td><td>1/20/23</td><td>3b</td><td>1/23/23</td><td>2/20/23</td><td>Analyst Screen-Out</td></tr>
<tr><td colspan="10">Analyst Justification. This condition is not discussed in any IR to date, the LER remains open. On October 30, 2022, the actuator for AFW flow control valve 1AF-51, which had been replaced on October 22nd during the refueling outage, malfunctioned during the response to a reactor trip. The licensee determined that both motor-driven AFW pumps were inoperable due to this failure beginning on October 27th when the plant entered Mode 3 coming out of their refueling outage. The turbine-driven AFW pump was also inoperable from October 27th to October 29th due to planned maintenance. A search of LERs did not yield any windowed events. Flow control valve 1AF-51 is normally open and is located in the common discharge header of the motor-driven AFW pumps to SG ‘B’. Flow control valve 1AF-51 serves two purposes: (a) it must be capable of automatically opening upon any auto-start signal for the motor-driven AFW pumps and (b) it must automatically close on a AFW isolation signal. The actuator malfunction did not affect flow control valve 1AF-51 ability to open. In addition, valve 1AF-93 was operable and can be used to control SG ‘B’ level as operators showed in the October 30th post-trip response. Valve 1AF-93 can also be used to isolate the SG ‘B’ if needed. Given that the condition occurred in Mode 3 and the redundancy in controlling and isolating flow to SG ‘B’, the risk associated with this degraded condition is qualitatively judged to be minimal and, therefore, this condition is not a precursor.</td></tr>
<tr><td>Susquehanna 2</td><td>388-22-001</td><td>9/26/22</td><td>Inadequate Performance of Loss of Safety Determination Resulting in Both Divisions of Core Spray Being Inoperable</td><td>11/23/22</td><td>1/3/22</td><td>3d</td><td>1/6/23</td><td>2/20/23</td><td>Analyst Screen-Out</td></tr>
<tr><td colspan="10">Analyst Justification. This condition is not discussed in any IR to date; the LER remains open. On September 26, 2022, the licensee performed quarterly stroke time testing of the emergency service water (ESW) isolation valves to turbine building closed cooling water and reactor building closed cooling water systems. Performance of this surveillance resulted in the inoperability of the division ‘2’ of the LPCS system for 9 minutes. The division ‘1’ of LPCS was inoperable due to planned maintenance during this time. The licensee failed to recognize that performing the surveillance test of the division ‘2’ ESW isolation valves while division ‘1’ of LPCS was inoperable would result in complete loss of the LPCS system. However, a licensee engineering analysis determined that division ‘2’of LPCS could have performed its safety function during valve testing because LPCS room temperature would not have exceeded functionality limits during a complete loss of room cooling. Since the division ‘2’ of LPCS remained functional, this condition is not a precursor, and a review of potential windowed events was not needed.</td></tr>
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