POLICY ISSUE
INFORMATION

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FOR: The Commissioners

FROM: Luis A. Reyes
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SUBJECT: STATUS OF THE ACCIDENT SEQUENCE PRECURSOR PROGRAM AND THE DEVELOPMENT OF STANDARDIZED PLANT ANALYSIS RISK MODELS

PURPOSE:

To inform the Commission of the status of the Accident Sequence Precursor (ASP) Program, provide the annual quantitative ASP results, and communicate the status of the development of the Standardized Plant Analysis Risk (SPAR) models. This paper does not address any new commitments or resource implications.

SUMMARY:

This report discusses the following activities, which the staff has performed since the last status report (SECY-05-0192), dated October 24, 2005:

- completion of the analysis of the fiscal year (FY) 2004 and FY 2005 events to identify precursors (i.e., events with a conditional core damage probability (CCDP) or increase in core damage probability (ΔCDP) that is greater than or equal to 1×10^{-6})

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- review of the status of the screening and analyses of events for FY 2006 to identify *significant* precursors, defined as CCDP or ΔCDP that is greater than or equal to 1×10^{-3}
- evaluation of precursor data to identify statistically significant adverse trends for the Industry Trends Program
- implementation of process changes to further improve ASP efficiency and timeliness
- review of status and progress on SPAR model development, including activities under the Risk Assessment Standardization Project (RASP)
- identification of SPAR model and other probabilistic risk assessment (PRA) lessons learned during Mitigating Systems Performance Index (MSPI) development and implementation
- resolution of organizational conflict of interest concerns with the contractor (Idaho National Laboratory) for several projects including SPAR model development

In addition, this report summarizes related upcoming activities for the next 12 months.

BACKGROUND:

In a memorandum to the Chairman dated April 24, 1992, the staff of the U.S. Nuclear Regulatory Commission (NRC) committed to report periodically to the Commission on the status of the ASP Program. In SECY-94-268, dated October 31, 1994, the staff made two significant changes to the report. First, the staff committed to provide the report annually, and second, the staff began to provide annual quantitative ASP results. The ASP Program systematically evaluates U.S. nuclear power plant operating experience to identify, document, and rank the operating events that were most likely to have led to inadequate core cooling and severe core damage (precursors), accounting for the likelihood of additional failures.

In SECY-02-141, dated March 8, 2002, the staff expanded the annual ASP SECY paper to include detailed information on the status of the SPAR Model Development Program. The objective of the SPAR Model Development Program is to develop standardized risk analysis models and tools that staff analysts use in many regulatory activities.

DISCUSSION:

This section summarizes the status, accomplishments, and results of each program since the previous status report, SECY-05-0192, dated October 24, 2005.

Status of the ASP Program and SPAR Model Development Program

The following subsections summarize the status of ongoing activities and the accomplishments of the ASP Program and SPAR Model Development Program. Enclosure 1 to this paper provides additional background and detail of the status of these two programs, while Enclosure 2 provides details of ASP results, trends, and insights.

ASP Program

- In SECY-04-0210, dated November 8, 2004, the staff informed the Commission of a plan to improve the timeliness of ASP analyses and complete the analysis of prior years' precursor events. We have completed the analyses of all precursor events that were identified in FY 2004 (17 precursors) and FY 2005 (15 precursors). The staff has begun the analysis of approximately 50 events in FY 2006 that were identified as potential precursors (i.e., CCDP or ΔCDP greater than or equal to $1{\times}10^{-6}$).

- The staff completed the screening for FY 2006 events for *significant* precursors (i.e., CCDP or ΔCDP greater than or equal to $1{\times}10^{-3}$). The staff identified no *significant* precursors in FY 2005 and FY 2006. In addition, the staff identified no statistically significant trend for *significant* precursors during the FY 1996–2005 period.

- The risk contribution from all precursors as measured by the integrated ASP index was generally constant during the period from FY 1996 through FY 2005 and has decreased since FY 2003.

- The staff evaluated precursor data through FY 2005 to identify statistically significant adverse trends for the Industry Trends Program. The data for the rates of occurrence of all precursors during the period from FY 1996 through FY 2005 were divided into two statistically distinct groups, FY 1996–2000 and FY 2001–2005.[1] The analysis detected no statistically significant trend for either of these 5-year periods. Enclosure 2 documents the results of this evaluation.

- Over the more recent time period from FY 2001–2005, the analysis detected a statistically significant decreasing trend for higher risk precursors (i.e., CCDP or ΔCDP greater than or equal to $1{\times}10^{-4}$).

- The staff implemented an initiative to further improve the timeliness of ASP analyses by streamlining the analysis and review processes. The analysis process will now include results from the Significance Determination Process (SDP) and Management Directive (MD) 8.3, "NRC Incident Investigation Program," when practicable. This action will prevent duplication of analyses and reduce unintended consequences of inconsistent outcomes. The staff has streamlined the review process to reduce the number of ASP analyses that undergo formal peer review. This revised review process will reduce administrative and review burdens to NRC staff and licensees for cases where formal peer reviews are considered of minimal value. However, rigorous independent reviews will continue to be performed by ASP Program analysts for all ASP analyses.

SPAR Model Development Program

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[1] In SECY-05-0192, the staff reported a step increase in the mean occurrence rate of all precursors at about the FY 2000 time frame. This step increase was found to be attributed to (1) an increase in scope of the ASP Program starting in FY 2000 (e.g., inclusion of potential precursors involving fire, external events, high-energy line breaks, and internal flooding), (2) one outlier group of 11 precursors involving cracks in control rod drive mechanism housings between FY 2001 and FY 2003, which also would be considered part of the scope increase (i.e., classified prior to FY 2000 as impractical to analyze) and (3) a second outlier group of 18 precursors involving loss of offsite power events during the FY 2001–2005 period. The NRC has implemented several initiatives to address these outlier events.

The staff continued work to improve the quality of SPAR models and to add efficiency to the evaluation process that use these models. Specifically, the staff:

- Continued to develop enhancements to Revision 3 SPAR models. A total of 39 plant models (out of 72 models) have been completed so far. This effort involved a detailed individual accident scenario level review against the respective licensee's plant PRA. In addition, SPAR model enhancements include the resolution of the PRA modeling issues that were previously identified during the onsite quality reviews of the SPAR models, MSPI pilot program reviews, and through feedback from model users.

- Incorporated external initiating events (i.e., internal fires, floods, and seismic events) into the Revision 3 SPAR models for nine plants.

- Developed a user-friendly interface for SDP assessments using the Revision 3 SPAR models.

- Developed initial SPAR models for 11 lead plants for internal initiating events during low-power and shutdown (LP/SD) operations.

- Developed SPAR models for calculating the large early release frequency (LERF) for the lead plants in six plant classes, representing varying plant and containment designs.

- Completed the first draft of a SPAR model quality assurance plan and formulation of a process for the integration of internal events, external events, LP/SD, and LERF modules into a comprehensive SPAR model for each plant.

- Interacted with the Advisory Committee on Reactor Safeguards (ACRS) in its quality review of the SPAR Model Development Program, specifically, as the models have been applied to the reevaluation of station blackout risk at nuclear power plants. The ACRS concluded that the overall quality of this project was more than satisfactory and the results met research objectives.

- Used SPAR models to support the implementation of the MSPI by verifying licensee results and by helping resolve the PRA quality issue. Enclosure 1 discusses this in more detail. Enclosure 3 documents the lessons learned in terms of changes to licensee PRA models and to the SPAR models.

In a September 28, 2005 memorandum, the Office of the General Counsel identified potential organizational conflict of interest concerns with the contractor (Idaho National Laboratory) for several projects including those for SPAR model development. The granting of a waiver in the third quarter of FY 2006 has allowed SPAR model development and RASP projects to proceed. This issue has impacted activities and schedules related to the SPAR Model Development Program and implementation of guidelines under RASP, and delayed a number of tasks scheduled for completion in FY 2006 and early FY 2007. Specifically, these delays impacted the development of SPAR models for LP/SD operations and external event initiators, and the development of detailed guidelines for the use of SPAR models for LP/SD operations, external event initiators, and calculation of LERF. Agency programs that were impacted by these delays included the SDP, ASP Program, and the MD 8.3 Program.

Upcoming Activities

The staff has planned the following activities for the next 12 months:

- Use the SPAR models to support the development of the state-of-the-art realistic consequence analysis of severe accidents at nuclear power plants to determine risk significant accident scenarios taking into consideration current plant capabilities.

- Identify and complete the preliminary analysis of *significant* precursors that occur through June 30, 2007, to support the agency's Strategic Plan goals for monitoring performance.

- Continue the screening, review, and analysis (preliminary and final) of events for FY 2006 and FY 2007, using MD 8.3 and SDP results when available, under the revised, streamlined ASP process.

- Complete the preliminary assessment of all FY 2006 ASP events to support the Agency Action Review Meeting, by April 2007. In addition, preliminary assessments will also be completed for events occurring during the first quarter of FY 2007 for those events where the inspection reports are completed during that quarter.

- Continue enhancing the Revision 3 SPAR models for internal events during power operations. Major activities include re-examination of several of the MSPI pilot models and completion of enhanced models for non-MSPI plants.

- Continue developing SPAR models for internal events during LP/SD operations, LERF, and external events in accordance with the current SPAR Model Development Plan. Plans are to complete three external events models for boiling-water reactors, and five additional LP/SD models.

- Continue implementing RASP, including streamlining and coordinating ASP and SDP analyses, and implementing guidelines for the application of SPAR models to operating events analysis.

<u>CONCLUSIONS</u>

The ASP Program continues to evaluate the safety significance of operating events at nuclear power plants and to provide insights to NRC's regulatory programs. The SPAR model development program is continuing to develop and improve independent risk analysis tools and capabilities to support the use of PRA in the agency's risk-informed regulatory activities. The staff uses SPAR models to support the Reactor Oversight Process, the ASP Program, the MD 8.3 evaluations, and the Generic Safety Issue resolution process. The staff also uses SPAR models to perform analyses in support of risk-informed reviews of license amendments and to independently verify the MSPI.

<u>RESOURCE</u>:

Resources to support the ASP Program are $600K and 5.3 full-time equivalents (FTE) in FY 2007, and $700K and 5.3 FTE in FY 2008. Resources for the SPAR Model Development Program are $2,770K and 2.8 FTE in FY 2007 and 2,660K and 2.9 FTE in FY 2008. These resources are contained in the FY 2008 budget.

COORDINATION:

The Office of the General Counsel reviewed this Commission paper and has no legal objection. The Chief Financial Officer reviewed this package and determined that it has no financial impact.

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Enclosures:
1. Status of the Accident Sequence Precursor Program and the Standardized Plant Analysis Risk Model Development Program
2. Results, Trends, and Insights from the Accident Sequence Precursor Program
3. SPAR Model and Other Probabilistic Risk Assessment Lessons Learned from Mitigating Systems Performance Indicator Development and Implementation

Status of the Accident Sequence Precursor Program and the Standardized Plant Analysis Risk Model Development Program

1.0 Accident Sequence Precursor Program Background

The Nuclear Regulatory Commission (NRC) established the Accident Sequence Precursor (ASP Program in 1979 in response to the “Risk Assessment Review Group Report” (NUREG/CR-0400, dated September 1978). The ASP Program systematically evaluates U.S. nuclear power plant operating experience to identify, document, and rank the operating events that were most likely to have led to inadequate core cooling and severe core damage (precursors), accounting for the likelihood of additional failures.

To identify potential precursors, NRC staff reviews plant events from licensee event reports (LERs), inspection reports, and special requests from NRC staff. The staff then analyzes any identified potential precursors by calculating a probability of an event leading to a core damage state. A plant event can be one of two types, either (1) an occurrence of an initiating event, such as a reactor trip or a loss of offsite power (LOOP), with any subsequent equipment unavailability or degradation, or (2) a degraded plant condition depicted by unavailability or degradation of equipment without the occurrence of an initiating event.

For the first type, the staff calculates a conditional core damage probability (CCDP). This metric represents a conditional probability that a core damage state is reached, given an occurrence of an initiating event (and any subsequent equipment failure or degradation).

For the second type, the staff calculates an increase in core damage probability (ΔCDP). This metric represents the increase in the probability of reaching a core damage state for the period that a piece of equipment or a combination of equipment is deemed unavailable or degraded from a nominal core damage probability for the same period for which the nominal failure or unavailability probability is assumed for the subject equipment.

The ASP Program considers an event with a CCDP or a ΔCDP greater than or equal to 1×10^{-6} to be a precursor. The ASP Program defines a *significant* precursor as an event with a CCDP or ΔCDP greater than or equal to 1×10^{-3}.

Program objectives. The ASP Program has the following objectives:

- provide a comprehensive, risk-informed view of nuclear power plant operating experience and provide a measure for trending nuclear power plant core damage risk
- provide a partial check on dominant core damage scenarios predicted by probabilistic risk assessments (PRAs)
- provide feedback to regulatory activities

The NRC also uses the ASP Program to monitor performance against the safety goal established in the agency's Strategic Plan. (See NUREG-1100, Vol. 22, "Performance Budget: Fiscal Year 2007," dated February 2006.) Specifically, the program provides input to the following performance measures:

- zero events per year identified as a *significant* precursor of a nuclear reactor accident (i.e., CCDP or ΔCDP greater than or equal to 1×10^{-3})

- no more than one significant adverse trend in industry safety performance (determination principally made from the Reactor Oversight Program (ROP) but supported by ASP results)

Program scope. The ASP Program is one of three agency programs that assess the risk significance of issues and events. (The other two programs are the significance determination process (SDP) and the event response evaluation process, as defined in Management Directive (MD) 8.3, "NRC Incident Investigation Program.") Compared to the other two programs, the ASP Program assesses the significance of a different scope of operating experience at U.S. nuclear power plants. For example, compared to the SDP, the ASP Program analyzes initiating events, as well as degraded conditions where there was no identified deficiency in the licensee's performance. The ASP Program scope also includes events with concurrent, multiple degraded conditions.

2.0 ASP Program Status

Analysis of ASP events. Table 1 of Enclosure 2 to this paper provides the status of events identified as potential precursors under the ASP Program. The staff has completed all precursor analyses from fiscal year (FY) 2004 and FY 2005. The analyses of FY 2006 events are in progress.

Control rod drive mechanism (CRDM) cracking events. The staff completed an analysis for the conditions involving primary water stress-corrosion cracking of CRDM housings initially discovered at 11 plants in FY 2001–2003. The staff is currently documenting and reviewing the analyses. The Office of Nuclear Regulatory Research (RES) has coordinated with the Office of Nuclear Reactor Regulation (NRR) on input for several of these analyses. To complete the remainder of the analyses, the staff decided to simplify the inputs for initiating event frequencies and potential sump-clogging probabilities. This simplification is justified since the staff had determined that more detailed analysis did not result in additional insights. This simplification did not affect ASP trends and results, and the staff has included these events in the total count and trending of all precursors (i.e., CCDP or ΔCDP $\geq 1 \times 10^{-6}$).

ASP Program status. The staff plans to complete its preliminary assessments of all FY 2006 events by April 2007 and complete all FY 2006 analyses by September 2007. In addition, the ASP Program will give priority to analyses of potentially high-risk events when such events are identified during NRC inspections or in LERs.

Investigation of trends and engineering insights. From its analysis of ASP data, the staff has developed and investigated trends to better understand their causes. Enclosure 2 provides the details.

ASP streamlining. In June 2006, the staff implemented changes to streamline the ASP process and thus improve ASP timeliness and efficiency. Although the objectives of the ASP, SDP, and MD 8.3 are different, the risk models and technical methods used are generally similar. One of the objectives of ASP streamlining is to gain efficiencies by using results from the SDP and MD 8.3 evaluations, where applicable, in the ASP Program. Another major objective is to achieve better coordination among the ASP, SDP, and MD 8.3 Programs. Better coordination will increase the timeliness of all three programs. The following summarizes the new process:

Selection of precursors with an SDP or documented MD 8.3 evaluation. For degraded conditions or significant operational occurrences for which there is an SDP or documented MD 8.3 quantitative risk evaluation, the ASP Program will utilize the results of these evaluations, where applicable, without performing a separate ASP analysis. As in the past, NRR and the regions will be performing the SDP and MD 8.3 evaluations using the respective program's process and guidelines. It is not the intent of this ASP Program change to propose changes to the SDP or MD 8.3 processes; rather, the ASP Program will use documented results from these processes where appropriate and applicable. As part of the NRR user need request on the Risk Assessment Standardization Project (RASP), RES will continue to provide technical assistance to NRR or the regional senior reactor analysts (SRAs), when requested, in utilizing or modifying the standardized plant analysis risk (SPAR) models as part of SDP Phase 3 or MD 8.3 analyses.

Selection of precursors with no SDP or documented MD 8.3 evaluation. The ASP Program will continue to perform analyses for events for which there is no SDP or MD 8.3 evaluation. Examples of these types of events include most initiating events and plant conditions where there are no performance deficiencies. In addition, because of differences in the objectives of the ASP and SDP Programs, in cases where there are concurrent multiple degraded conditions, the ASP process will analyze these conditions together. (The SDP Program analyzes concurrent multiple degraded conditions that involve different performance deficiencies individually.) In performing these ASP analyses, RES will continue to interact with NRR and the SRAs in obtaining plant and event information/data and to discuss results on an ongoing basis.

Potentially significant precursors. For all events (including those being evaluated by the SDP or MD 8.3 processes) that, based on preliminary evaluations, could be significant precursors (defined as events with CCDPs or ΔCDPs greater than or equal to 1×10^{-3}), the ASP Program will perform an expedited analysis to support the reporting requirements in the annual NRC Performance and Accountability Report to Congress and to support the proposed new abnormal occurrence criteria described in SECY-05-0137. In performing these ASP analyses, RES will interact closely with NRR and the regions to obtain plant and event information/data and to discuss results on an ongoing basis.

New peer review process. As part of the new ASP process, the staff will revise the peer review process to make it more efficient. For lower risk events, if the ASP analysis results in a CCDP or ΔCDP of less than 1×10^{-4}, RES will no longer request formal NRR, regional office, or licensee review. RES will issue a summary of the analysis results by memorandum to NRR, the regional offices, and the licensee for information. If NRR, the regional offices, or the licensee chooses to comment on these analyses, RES will continue to address these comments and revise the ASP analysis if necessary. For higher risk events (i.e., for ASP analysis results greater than 1×10^{-4}), RES will continue to request formal review comments by NRR, the regional offices, and the licensee. The staff will issue these ASP analyses as final after resolution of peer review comments. This revised review process will reduce administrative and review burdens to NRC staff and licensees.

3.0 SPAR Model Development Program Background

The objective of the SPAR Model Development Program is to develop standardized risk analysis models and tools that staff analysts use in many regulatory activities, including the ASP Program and Phase 3 of the SDP. The SPAR models have evolved from two sets of simplified event trees initially used to perform precursor analyses in the early 1980s. Today's Level 1, Revision 3, SPAR models for internal events are far more comprehensive than their predecessors. For example, the revised SPAR models include a new, improved LOOP/station blackout (LOOP/SBO) module, improved reactor coolant pump seal failure model, and updated estimates of accident initiator frequencies and equipment reliability based on more recent operating experience data.

The Level 1, Revision 3, SPAR models consist of a standardized, plant-specific set of risk models that use the event-tree/fault-tree linking methodology. They employ an NRC-developed standard approach for event-tree development, as well as a standard approach for input data for initiating event frequencies, equipment performance, and human performance. These input data can be modified to be more plant- and event-specific when needed. The system fault trees contained in the SPAR models are not as detailed as those contained in licensees' PRAs. The initial set of 72 Revision 3 SPAR models, representing all 103 operating units, was completed and benchmarked against licensee PRAs during the onsite quality assurance reviews of these models. On the whole, the results of the benchmarking indicate that the difference observed between the SPAR models and the licensee plant PRAs is not very significant from an overall risk standpoint.

In 1999, the SPAR Model Users Group (SMUG) assumed coordination of model development efforts that support the ASP Program and other risk-informed regulatory processes. This group consists of representatives from RES, NRR, and the NRC's regional offices. In August 2000, the SMUG completed the SPAR Model Development Plan, which addresses the following models:

- internal initiating events during full-power operation (Revision 3 SPAR models)
- internal initiating events during low-power and shutdown (LP/SD) operations
- external initiating events (including fires, floods, and seismic events)
- calculation of large early release frequency (LERF)

In addition to SMUG, the NRC staff initiated the Risk Assessment Standardization Project (RASP) in February 2004. The primary focus of RASP is to standardize risk analyses in SDP Phase 3, ASP, and MD 8.3. Under this project, the NRC staff is working to complete the following activities:

- enhance SPAR models to be more plant-specific and enhance the codes used to manipulate the SPAR models

- document consistent methods and guidelines for risk assessments of internal events during power operations, internal fires and floods, external events (e.g., seismic events and tornadoes), internal events during LP/SD operations, and LERF sequences

- provide on-call technical support to NRR and regional senior reactor analysts

4.0 Recent Achievements

The SPAR Model Development Program continues to play an integral role in the ASP analysis of operating events. Many other agency activities, such as the Reactor Oversight Program (ROP), MD 8.3 evaluations, licensing actions, and the Mitigating Systems Performance Index (MSPI), involve the use of SPAR models. New SPAR models are under development in response to staff needs for modeling internal initiating events during LP/SD operations, external initiating events, and LERFs.

One recent example of the use of SPAR to support agency work is the assessment of SBO risk. Enhanced SPAR models were applied to this assessment. In FY 2006, the NRC issued NUREG/CR-6890, "Reevaluation of Station Blackout Risk at Nuclear Power Plants." Volume 1 of the report contains updates of LOOP initiating event frequencies and nonrecovery probabilities. Volume 2 presents SBO risk estimates in terms of core damage frequency (CDF) for the nuclear industry and the fleet of nuclear power plants. Volume 3 contains the resolution of comments. The report concludes that LOOP frequencies have decreased, but duration times have increased. The study also shows that SBO CDF estimates have decreased. The baseline results reflect improving emergency diesel generator performance, improving plant-specific SBO coping capabilities (e.g., turbine-driven pump performance), increasing duration of LOOP events, and lower overall loss of offsite power frequency observed during the 1997–2003 period.

Another example of the use of SPAR is the MSPI project. The staff used the SPAR models as part of its review of the technical adequacy of the licensee PRA models for MSPI implementation in FY 2006. The staff reviewed design features, operations features, or modeling methods, as appropriate and made cross-comparisons with SPAR model results. The staff noted differences or outliers and discussed their basis with the licensees. The staff continued to work with licensees until it had resolved all MSPI outlier concerns. The industry implemented over a dozen PRA model changes as a result of this comprehensive review effort. In summary, the use of SPAR models proved to be invaluable in resolving PRA adequacy concerns for implementation of MSPI. Enclosure 3 discusses this in more detail.

The staff is currently using SPAR models to support the development of the state-of-the-art reactor consequence analysis of severe accidents at nuclear power plants. Based on insights resulting from this activity, the staff plans to update the SPAR models, as appropriate, based on current plant capabilities and safety enhancements. Initially, the plants to be evaluated will be the six lead (pilot) plants in the state-of-the-art reactor consequence analysis project. In addition, the staff will update the SPAR models, as appropriate and on a plant-by-plant basis, to include plant safety enhancements resulting from Phases 1, 2 and 3 Section B.5.b assessments as the engineering and risk information on the pertinent systems become available to the staff as part of normal NRC regulatory activities.

5.0 SPAR Model Development Status

In conformance with the SPAR Model Development Plan, the staff has completed the following activities in model and method development since the previous status report (SECY-05-0192).

SPAR models for analysis of internal initiating events during full-power operation

- The staff developed enhanced Revision 3 SPAR models in response to an NRR user need. This effort involved (1) performing a cut-set-level review against the respective licensee's plant PRA for each of the Revision 3 SPAR models for 39 models that were not pilot plants in the MSPI Program, and (2) incorporating into the Revision 3 SPAR models the resolution of the PRA modeling issues that were identified (a) during the onsite quality assurance (QA) reviews of the Revision 3 SPAR models, (b) during the MSPI pilot program reviews, and (c) based on feedback from model users.

SPAR models for analysis of internal initiating events during LP/SD operation

- This effort is part of the RASP in support of ASP and SDP Phase 3 analyses.

- Before 2006, the staff had completed initial development of 11 LP/SD SPAR models. It completed no additional models in FY 2006 because of a potential conflict of interest with the NRC contractor at Idaho National Laboratory (INL). The staff has resolved this issue with INL and is now preparing additional LP/SD models in anticipation of onsite quality assurance (QA) reviews.

SPAR models for the calculation of LERF

- This effort is part of the RASP in support of ASP and SDP Phase 3 analyses. The staff completed the LERF SPAR model for Grand Gulf (the lead plant in the fourth class), which is a boiling-water reactor (BWR) with a Mark III containment. The staff subsequently sent the model to the licensee in the course of preparing for the onsite QA review of the model against the Level 2/LERF model.

- The staff also completed models for the lead plant (LaSalle) in the fifth plant class (BWRs with Mark II containments) and the sixth plant class (pressurized-water reactors (PWRs) with subatmospheric containments) in FY 2006.

SPAR models for the analysis of external events

- The staff is performing this effort, which is part of the RASP in support of ASP and SDP Phase 3 analyses, in conjunction with NRR's SDP external events Phase 2 worksheet benchmarking program.

- Nine preliminary SPAR models that contain internal and external events are complete and are available for trial use and evaluation by the staff.

6.0 Additional Achievements

Validation of SPAR models*.* Validation of the SPAR models is an ongoing effort. The staff compared the SPAR models to the plant PRA models during SDP Phase 2 Notebook plant visits and MSPI reviews and considered feedback from SDP and ASP analysts. The licensees have also provided feedback, which the staff has incorporated as appropriate. Metrics are used to quantify the degree of agreement between the SPAR models and licensee PRAs. On the whole, this benchmarking has indicated that the CDFs from the SPAR models are within a factor of 2, on average, when compared to the estimates from the licensee PRA models. This is within the generally accepted uncertainty for internal event PRAs. Most of the differences are well understood and result from the use of plant-specific versus industry-averaged performance data. In some cases, a few key modeling assumptions account for relatively large differences between licensee PRA and SPAR model results. The reports for each SPAR model describe the benchmarking comparisons, as well as the significant modeling differences between the SPAR and licensee PRA models.

Advisory Committee on Reactor Safeguards Review. The Advisory Committee on Reactor Safeguards (ACRS) selected the SPAR Model Development Program as one of three projects to review during 2005 for "research quality." The ACRS found the SPAR Model Development Program and its application as part of NUREG/CR-6890, "Reevaluation of Station Blackout Risk at Nuclear Power Plants," to be "more than satisfactory" and found that the program and NUREG/CR results meet the research objectives. The ACRS also noted the value of SPAR models as an "independent capability to evaluate risk issues across the population of operating plants." The ACRS report entitled, "ACRS Assessment of the Quality of Selected NRC Research Projects," dated October 2005, documents the results of their review. This document is publically available and can be accessed from the NRC's Agencywide Documents Access and Management System (ADAMS Accession No. ML053110211).

Methods guidelines. The staff completed initial guidelines for performing risk assessments for the internal fire and flood initiators and external events during power operations in September 2006. The deliverable was in the form of a practical, "how to" handbook of methods, best practices, examples, tips, and precautions for applying the new SPAR models for external events that are under development. The staff issued this handbook for trial use. The staff and the contractor for ASP Program support have been using the trial-basis guidelines for internal events during power operations for over 1 year. The handbook has also proven useful to new analysts who recently started work on the ASP and reactor oversight process programs and will reduce the time and resources needed to train future new analysts. The staff began working on guidelines to address LP/SD operations and LERF. The staff developed draft guidance for the calculation of LERF, applied this guidance in an analysis of a recent LOOP event, and is currently evaluating the results of this pilot application. During FY 2007, the staff will issue a revision of the handbook that incorporates comments from users and expands discussion, guidance, and examples of internal and external events. Plans are to integrate all guidance into one handbook.

Efficiency improvements. Enhancements of the SPAR models, improvements to the Systems Analysis for Hands-on Integrated Reliability Evaluation (SAPHIRE) code, and the implementation of guidelines for agency risk applications all contribute to increased staff efficiency. SPAR models that accurately reflect plant design, operation, and performance result in improved turnaround time for SDP and ASP analyses. When the SPAR models substantially agree with the licensee's own PRA models, less time is required to resolve significant differences between the two models. Improvements to the SAPHIRE code allow efficient development and use of the SPAR models. A SAPHIRE version is under development which streamlines development of large, complex models, such as external events models and can solve integrated internal and external events SPAR models. In addition, improved guidelines for the application of SPAR models to operational events result in reduced training needs and greater standardization.

Finally, the staff is coordinating its development of SPAR fire models with the regulatory efforts under National Fire Protection Association (NFPA) 805, "Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants." Significant synergies and resource savings should result from early identification of fire PRA reporting requirements once licensees complete their fire PRA models and NFPA 805 submittals.

Results, Trends, and Insights from the Accident Sequence Precursor Program

This enclosure discusses the results of accident sequence precursor (ASP) analyses conducted by the U.S. Nuclear Regulatory Commission (NRC), as they relate to events that occurred during Fiscal Years (FY) 2004–2006. Based on those results, this document also discusses the NRC's analysis of historical ASP trends, and the evaluation of the related insights. The seven tables and nine figures that augment this discussion appear at the end of this enclosure.

1.0 ASP Event Analyses

Table 1 summarizes the status of the NRC's ASP analyses, as of September 30, 2006. Specifically, the table identifies ASP analyses that the NRC staff has completed for events that occurred during FY 2004–2006. (Note that, as of September 30, 2006, the staff had not yet screened all of the FY 2006 events.) The following subsections summarize the results of these analyses, which are further detailed in the associated Tables 1–7.

FY 2004 analyses. The ASP analyses for FY 2004 identified 17 precursors. Of the 17 precursors, 14 occurred while the plants were at power.

Table 2 presents the results of the staff's ASP analyses for FY 2004 precursors that involved initiating events, while Table 3 presents the analysis results for precursors that involved degraded conditions.

FY 2005 analyses. The ASP analyses for FY 2005 identified 15 precursors. Of the 15 precursors, 13 occurred while the plants were at power.

Table 4 presents the results of the staff's ASP analyses for FY 2005 precursors that involved initiating events, while Table 5 presents the analysis results for precursors that involved degraded conditions.

FY 2006 analyses. The staff has completed all screening and reviews for potential *significant* precursors (i.e., conditional core damage probability (CCDP) or increase in core damage probability (ΔCDP) $\geq 1\times10^{-3}$) through September 30, 2006. In particular, the staff reviewed a combination of licensee event reports (LERs) (as required by Title 10, Section 50.73, of the *Code of Federal Regulations*) and daily event notification reports (as required by Title 10, Section 50.72, of the *Code of Federal Regulations*) to identify potential *significant* precursors. The staff is still screening and reviewing LERs concerning other potential precursor events that occurred during FY 2006.[1] The goal is to complete preliminary assessments of all FY 2006 events by April 2007.

2.0 Industry Trends

This section discusses the results of trending analyses for all precursors and *significant* precursors.

Statistically significant trend. The trending method used in this analysis is consistent with those methods used in the staff's risk studies. (See Appendix E of Reference 1.) The trending method uses the p-value approach for determining the probability of observing a trend as a result of chance alone. A trend is considered statistically significant if the p-value is smaller than 0.05. The figures at the end of this enclosure show the p-value for each trend.

Data coverage. Most of the data used in the trending analyses span the period from FY 1996 through FY 2005. The trends include the results of both final and preliminary analyses of potential precursors. However, the following exception applies to the data coverage of the trending analyses:

- *Significant precursors.* The trend of *significant* precursors includes events that occurred during FY 2006. The results for FY 2006 are based on the staff's screening and review of a combination of LERs and daily event notification reports.[2] The staff analyzes all potential *significant* precursors immediately.

Precursor trend evaluation. Last year's status report (SECY-05-0192) documented an investigation into the apparent low number of

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[1] Licensees have a 60-day grace period after an event or discovery of a degraded condition to submit an LER.

[2] The staff has completed all screening and reviews through September 30, 2006.

precursors during FY 1997–1999 and the subsequent increase in FY 2000–2004. The main conclusions of that investigation were that ASP Program changes (e.g., inclusion of Reactor Oversight Process findings and inclusion of external initiated events) that occurred in FY 2001 significantly increased the number of precursors identified compared to those identified in previous years. In addition, recent groups of outlier events (e.g., the 2003 northeast U.S. electrical blackout resulting in 8 precursor events, the 11 control rod drive mechanism (CRDM) housing cracking conditions between FY 2000 and FY 2003) and the high number of loss of offsite power (LOOP) events that occurred in FY 2003 and FY 2004 were significant contributors to increasing trends.

The staff did not redo work performed as part of last year's analysis as part of this year's analysis. Instead, five-year trend analyses were performed for FY 1996–2000 and FY 2001–2005 periods for groups of precursor affected by the increase in ASP scope (i.e., precursors that involve degraded conditions) that occurred in FY 2001. For the precursor groups not affected by the increase in ASP scope (e.g., precursors involving initiating events), 10-year trend analyses were performed. Performing the trend analyses in this manner more accurately reflect precursor trends over a period when the analyses of events were consistently completed.

2.1 Occurrence Rate of All Precursors

The NRC's Industry Trends Program (ITP) provides the basis for addressing the agency's performance goal measure on the number of "statistically significant adverse industry trends in safety performance" (one measure associated with the safety goal established in the NRC's Strategic Plan). Precursors identified by the ASP Program are one indicator used by the ITP to assess industry performance.

Results. Figure 1 depicts the occurrence rate for all precursors by fiscal year during FY 1996–2000 and FY 2001–2005 periods. A review of the data for that period reveals the following insights:

- The analysis divided the data from FY 1996 through FY 2005 into two parts, FY 1996–2000 and FY 2001–2005, because of the ASP Program scope increased (e.g., inclusion of external events and significance determination process (SDP) findings) in FY 2000. These increases in scope have resulted in the identification of an increasing number of lower risk precursors (i.e., CCDP or ΔCDP $<10^{-4}$). The analysis identified no trend for either of these 5-year periods. The mean rate of occurrence of all precursors in the time period from FY 2001–2005 is higher than what is observed during FY 1996 through FY 2000. In addition to the increases in ASP Program scope, the increased number of outlier events (e.g., the 11 grid-related LOOP events in FY 2003 and FY 2004 and the 11 CRDM housing cracking events between FY 2001 and FY 2003) accounts for the observed change.

- Over the more recent time period from FY 2001–2005, the analysis detected a statistically significant decreasing trend for higher risk precursors (i.e., CCDP or ΔCDP $\geq 10^{-4}$).

2.2 Significant Precursors

The ASP Program provides the basis for the FY 2006 performance goal measure of "zero events per year identified as a *significant* precursor of a nuclear accident" (one measure associated with the safety goal established in the NRC's Strategic Plan).[3] Specifically, the Strategic Plan defines a *significant* precursor as an event that has a probability of at least 1 in 1000 ($\geq 10^{-3}$) of leading to a reactor accident (see Reference 2).

Table 6 summarizes all *significant* precursors that occurred from FY 1969 through FY 2006.

Results. Figure 2 depicts the number of *significant* precursors that occurred during FY 1996–2006. A review of the data for that period reveals the following insights:

- There were no *significant* precursors identified in FY 2006.

- The staff does not detect any statistically significant trend in the occurrence of *significant* precursors during FY 1996–2006. In addition, the analysis revealed no trend for *significant* precursors during the FY 2001–2006 period.

- Over the past 20 years, *significant* precursors have occurred, on average, about once every 4 years. The events in this group involve differing

[3] Before FY 2005, the performance goal measure for *significant* precursors was "no more than one event per year identified as a *significant* precursor of a nuclear accident."

failure modes, causes, and systems.

3.0 Insights and Other Trends

The following sections provide additional ASP trends and insights from the period FY 1996 through FY 2005.

3.1 Initiating Events vs. Degraded Conditions

A precursor can be the result of either (1) an operational event involving an initiating event such as a LOOP, or (2) a degraded condition found during a test, inspection, or engineering evaluation. A degraded condition involves a reduction in safety system reliability or function for a specific duration (although no reactor trip initiator actually occurred during this time that challenged the degraded condition).

A review of the data for FY 1996–2005 yields insights described below.

Initiating events

- Over the past 10 years, precursors involving degraded conditions outnumbered initiating events (69 percent compared to 31 percent, respectively). This predominance was most notable in FY 2001 and FY 2002, when degraded conditions contributed to 91 percent and 100 percent of the identified precursors, respectively.

- The mean occurrence rate of precursors involving initiating events exhibits an increasing trend that is statistically significant for the period from FY 1996 through FY 2005, as shown in Figure 3. Specifically, the occurrence rate of such precursors increased over this period by a factor of 3. The analysis detected no trend when the 2003 northeast blackout events are excluded from the data.

- Of the precursors involving initiating events during FY 1996–2005,64 percent are LOOP events. During the period from FY 2001 through FY 2005, 70 percent of all initiating event precursors involved a LOOP.

Degraded conditions

- The analysis divided the data from FY 1996 through FY 2005 into two parts, FY 1996–2000 and FY 2001–2005, because of the ASP Program scope increased (e.g., inclusion of external events and SDP findings) in FY 2000. The mean occurrence rate of precursors involving degraded conditions exhibits a statistically significant decreasing trend during the FY 2001–2005 period, as shown in Figure 4. The analysis detected no trend for the FY 1996–2000 period.

- From FY 1996 through FY 2005, approximately one-half of the precursors involving degraded conditions had a condition start date before FY 1996.

3.2 Precursors Caused by Degraded Conditions

Most precursors involving degraded conditions result from equipment unavailabilities. Such events typically occur for extended periods without a reactor trip, or in combination with a reactor trip in which a risk-important component is unable to perform its safety function as a result of a degraded condition.

A review of the data for FY 1996–2005 yields insights described below concerning the unavailability of safety-related equipment.[4]

Equipment unavailabilities at boiling-water reactors

- Of the 16 precursors involving the unavailability of safety-related equipment that occurred at boiling-water reactors (BWRs) during FY 1996–2005, most were caused by failures in the emergency power system (69 percent), residual heat removal system (31 percent), or high-pressure coolant injection system (13 percent).

Emergency core cooling systems in pressurized-water reactors

- The unavailability of safety-related high- and/or low-pressure injection trains contributed to 61 percent of all identified precursors that occurred at pressurized-water reactors (PWRs) during FY 1996–2005. Failures in either the emergency core cooling system (ECCS) (22 percent) or emergency power sources (18 percent) caused most of these unavailabilities, or they resulted from design-basis issues involving other structures or systems that impact either the

[4] The sum of percentages presented in this section does not always equal 100 percent because some precursors involve multiple equipment unavailabilities.

ECCS or one of its support systems (51 percent).

- A condition that affected sump recirculation during postulated loss-of-coolant accidents (LOCAs) of varying break sizes caused 25 of the precursors.

Auxiliary/emergency feedwater systems in PWRs

- The unavailability of one or more trains of the auxiliary and emergency feedwater (AFW/EFW) systems contributed to 39 percent of all precursors that occurred at PWRs. Most of these unavailabilities were the result of failures in the AFW/EFW systems (16 percent) or emergency power sources (35 percent), or they resulted from design-basis issues involving other structures or systems that impact either the AFW/EFW systems or one of their support systems (49 percent).

- The seven precursors that involved a failure in an AFW/EFW train yield the following insights:

  – Two of the train failures occurred following a reactor trip.

  – All seven of the precursors involved the unavailability of the turbine-driven AFW/EFW pump train.

Emergency power sources in PWRs

- The unavailability of emergency power sources such as emergency diesel generators (EDGs) and hydroelectric generators (at Oconee), contributed to 23 percent of all precursors that occurred at PWRs.[5] Most of these unavailabilities resulted from random hardware failures in the emergency power system (44 percent).

- The other unavailabilities were attributable to design-basis issues (36 percent) and losses of service water (20 percent).

- In all the analyzed LOOP events at PWRs, the turbine-driven AFW/EFW pumps were operable.

Section 3.3 discusses insights related to precursors that involved a LOOP with simultaneous EDG unavailability.

3.3 Precursors Involving LOOP Initiating Events

Six LOOP events occurred during FY 2004, while only one LOOP event occurred during 2005. The FY 2005 LOOP event occurred at Waterford, while the plant was shut down, and was caused by the effects of Hurricane Katrina.

Results. A review of the data for FY 1996–2005 leads to the following insights:

- The mean occurrence rate of precursors resulting from a LOOP does not exhibit a trend that is statistically significant for the period from FY 1996 through FY 2005, as shown in Figure 5. It is noted that the number of LOOP events in 2003 and 2004 is much higher than in previous years. The NRC has implemented initiatives to address this increase.

- Of the LOOP precursor events that occurred during FY 1996–2005, 11 percent had a CCDP $\geq 1\times10^{-4}$.

- A simultaneous unavailability of an emergency power system train was involved in 4 of the 27 LOOP precursor events during FY 1996–2005. One of these precursors was a *significant* precursor (Catawba Unit 2, 1996).

3.4 Precursors at BWRs vs. PWRs

Since FY 2001, 25 precursors have occurred at BWRs, which is 22 more than the total from the previous 5 years. Over the past 10 years, 109 precursors have occurred at PWRs, with approximately 60 percent occurring in the past 5 years.

A review of the data for FY 1996–2005 reveals the results for BWRs and PWRs described below.

BWRs

- The analysis divided the data from FY 1996 through FY 2005 into two parts, FY 1996–2000 and FY 2001–2005, because of the ASP Program scope increased (e.g., inclusion of external events and SDP findings) in FY 2000.

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5 Not all EDG unavailabilities are precursors. The ASP Program screens out an EDG unavailability for a period of less than one surveillance test cycle (1 month) is screened out in the ASP Program (assuming no other complications). In addition, the risk contributions of EDG unavailabilities vary from plant-to-plant and may result in a ΔCDP less than the threshold of a precursor (1×10^{-6}).

The analysis identified no trend for either of these 5-year periods, as shown in Figure 6. The mean rate of occurrence of precursors occurring at BWRs in the time period from FY 2001–2005 is higher than what is observed during FY 1996 through FY 2000. In addition to the increase in ASP Program scope, the large number of LOOP events that occurred at BWRs in FY 2003 account for the observed change.

- An average of three precursors per year occurred at BWRs during the FY 1996–2005 period.
- LOOP events contributed to 60 percent of precursors involving initiating events at BWRs.
- Only three precursors occurred at a BWR during the 5-year period from FY 1996 through FY 2000.

PWRs

- The analysis divided the data from FY 1996 through FY 2005 into two parts, FY 1996–2000 and FY 2001–2005, because of the ASP Program scope increased (e.g., inclusion of external events and SDP findings) in FY 2000. The analysis identified no trend for either of these 5-year periods, as shown in Figure 7. The mean rate of occurrence of precursors occurring at PWRs in the time period from FY 2001–2005 is higher than what is observed during FY 1996 through FY 2000. In addition to the increases in ASP Program scope, the increased number of outlier events (e.g., the 6 grid-related LOOP events in FY 2003 and FY 2004 and the 11 CRDM housing cracking events between FY 2001 and FY 2003) accounts for the observed change.
- An average of 11 precursors per year occurred at PWRs during FY 1996–2005.
- LOOP events contribute to 69 percent of precursors involving initiating events at PWRs.

3.5 Integrated ASP Index

The staff derives the integrated ASP index for order-of-magnitude comparisons with industry-average core damage frequency (CDF) estimates derived from probabilistic risk assessments (PRAs) and the NRC's Standardized Plant Analysis Risk (SPAR) models. The index or CDF from precursors for a given fiscal year is the sum of CCDPs and ΔCDPs in the fiscal year divided by the number of reactor-calendar years in the fiscal year.

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 exists). The risk contributions from precursors involving initiating events are included in the fiscal year that the event occurred.

Examples. A precursor involving a degraded condition is identified in FY 2003 and has a ΔCDP of 5×10^{-6}. A review of the LER reveals that the degraded condition has existed since a design modification performed in FY 2001. In the integrated ASP index, the ΔCDP of 5×10^{-6} is included in the FYs 2001, 2002, and 2003.

For an initiating event occurring in FY 2003, the CCDP from this precursor is included only in FY 2003.

Results. Figure 8 depicts the integrated ASP indices for FY 1996–2005. A review of the ASP indices leads to the following insights:

- Based on order of magnitude, the average integrated ASP index for the period from FY 1996 through FY 2005 is consistent with the CDF estimates from the SPAR models and the licensees' PRAs.
- The risk contribution from precursors is generally constant over this time period and has decreased since FY 2003.
- Contributions to the average integrated CDF from precursors over the 10-year period (FY 1996–2005) are as follows:
  - Four precursors contribute to nearly one-half (43 percent) of the average integrated CDF from precursors over the 10-year period. Specifically, long-term degraded conditions at Point Beach Units 1 and 2 (discovered in 2001) involved potential common-mode failure of all AFW pumps, while long-term degraded conditions at D.C. Cook Units 1 and 2 (discovered in 1999) involved a number of locations in the plant where the effects of postulated high-energy line break events would damage safety-related components. The associated ΔCDPs of the degraded conditions at Point Beach and D.C. Cook

were high (7×10^{-4} and 4×10^{-4}, respectively) and the degraded conditions had existed since plant construction.

- Two *significant* precursors (i.e., CCDP or ΔCDP $\geq 1\times10^{-3}$) contribute to 25 percent of the average integrated CDF from precursors over the 10-year period. Each *significant* precursor existed for a 1-year period. Table 6 describes these events.

- The remaining 32 percent of the average integrated CDF from precursors over the 10-year period was from contributions from 131 precursors.

Limitations. Using CCDPs and ΔCDPs from ASP results to estimate CDF is difficult because (1) the mathematical relationship requires a significant level of detail, (2) statistics for frequency of occurrence of specific precursor events are sparse, and (3) the assessment must also account for events and conditions that did not meet the ASP precursor criteria.

The integrated ASP index provides the contribution of risk (per FY) resulting from precursors and cannot be used for direct trending purposes since the discovery of precursors involving longer term degraded conditions in future years may change the cumulative risk from the previous year(s). Because of these and other limitations, the staff has primarily used the rate of CCDPs and ΔCDPs as a trending indication.

3.6 Consistency with PRAs and IPEs

A secondary objective of the ASP Program is to provide a partial validation of the dominant core damage scenarios predicted by PRAs and individual plant examinations (IPEs). Most of the identified precursor events are consistent with failure combinations identified in PRAs and IPEs.

However, a review of the precursor events for FY 1996–2005 reveals that approximately 36 percent of the identified precursors involved event initiators or failure modes that were not explicitly modeled in the PRA or IPE for the specific plant where the precursor event occurred. Table 7 lists these precursors. The occurrence of these precursors does not imply that explicit modeling is needed; however, such modeling could yield insights that could be incorporated in future revisions of the PRA.

3.7 Review of Human Error Contributions

The staff reviewed precursor data from the ASP Program during the FY 2000–2004 period to identify the kinds of human errors that are associated with precursor events. In this updated review, the staff used the classification scheme and approach developed in previous studies (References 3 and 4) of the same subject. In addition, the staff identified and compared human errors associated with select Green inspection findings during FY 2004 the human errors associated with higher risk precursor events. The following summarizes these findings:

- *Number of human errors in precursors.* The average number of errors per precursor was approximately three. Although precursors can involve multiple error events, the CCDP or ΔCDP for these precursors was generally low (in the 10^{-6} to 10^{-5} range), an indication that sufficient redundancy and defense-in-depth remained.

- *Error contributions to precursors.* Figure 9 shows the percentage of precursors with at least one error in a subcategory. When the percentage of precursors with at least one error in the subcategory is considered, the dominant subcategories are inadequate procedures/procedure development (39 percent); design deficiencies (33 percent); inadequate engineering evaluation/review (28 percent); failure to correct known deficiencies (25 percent); inadequate maintenance and testing practices (18 percent); issues with management oversight (15 percent); and incorrect operator action/inaction (14 percent).

- *Higher risk precursors.* The staff reviewed precursors with a CCDP or ΔCDP greater than or equal to 1×10^{-5} to identify the error(s) that contributed most to the overall risk of the initiating event (CCDP) or degraded condition (ΔCDP).

  Of the 30 higher risk precursors, design-related errors caused 35 percent. Errors in the Design and Engineering category contributed to the risk of 9 out of 18 degraded conditions and 2 out of 13 initiating events.

  Of the 13 precursors involving initiating events, 11 had no significant risk contribution from human errors. Most of these events involved a LOOP initiator caused by a fault outside the plant boundary, such as grid-related and hurricane-related LOOP events.

4.0 Summary

This section summarizes the ASP results, trends, and insights.

- ***Significant precursors.*** No *significant* precursors (i.e., CCDP or ΔCDP $\geq 1\times10^{-3}$) were identified in FYs 2005 or 2006. The ASP Program provides the basis for the FY 2005 performance goal measure of “zero events per year identified as a *significant* precursor of a nuclear accident.” The NRC’s Performance and Accountability Report for FY 2006 and the NRC Performance Budget for FY 2007 will report these results.

- ***Occurrence rate of all precursors.*** The analysis divided the data from FY 1996 through FY 2005 into two parts, FY 1996–2000 and FY 2001–2005, because of the ASP Program scope increased (e.g., inclusion of external events and SDP findings) in FY 2000. These increases in scope have resulted in the identification of an increasing number of lower risk precursors (i.e., CCDP or ΔCDP $<10^{-4}$). The analysis identified no trend for either of these 5-year periods. The mean rate of occurrence of all precursors in the time period from FY 2001–2005 is higher than what is observed during FY 1996 through FY 2000. In addition to the increases in ASP Program scope, the increased number of outlier events (e.g., the 11 grid-related LOOP events in FY 2003 and FY 2004 and the 11 CRDM housing cracking events between FY 2001 and FY 2003) accounts for the observed change.

  Over the more recent time period from FY 2001–2005, the analysis detected a statistically significant decreasing trend for higher risk precursors (i.e., CCDP or ΔCDP $\geq 10^{-4}$).

  The ITP uses this trend as one of the agency’s monitored indicators. The NRC's Performance and Accountability Report for FY 2006 and the NRC Performance Budget for FY 2007 will report these results.

5.0 References

1. U.S. Nuclear Regulatory Commission. NUREG/CR-5750, “Rates of Initiating Events at U.S. Nuclear Power Plants: 1987–1995.” Washington, DC. February 1999.

2. U.S. Nuclear Regulatory Commission. NUREG-1100, Vol. 21, “Performance Budget, Fiscal Year 2006.” Washington, DC. February 2005.

3. U.S. Nuclear Regulatory Commission. NUREG/CR-6753, “Review of Findings for Human Performance Contribution to Risk in Operating Events.” Washington DC. August 2001.

4. U.S. Nuclear Regulatory Commission. NUREG/CR-6775, “Human Performance Characterization in the Reactor Oversight Process.” Washington, DC. September 2001.

Table 1. Status of ASP analyses (as of September 30, 2006).

Status	FY 2004	FY 2005	FY 2006[a]
Analyzed events that were determined not to be precursors	27	32	2
Events to be further analyzed	--	--	50
ASP precursor analyses	15	7	–[b]
SDP (or MD 8.3) results used for ASP program input	2	8	–[b]
Total precursors identified	17	15	--

a. As of September 30, 2006, the staff has not yet screened all of the FY 2006 events and unavailabilities.
b. Based on historical data, expectations are that approximately 40 percent of ASP precursors will use SDP or MD 8.3 results.

Table 2. FY 2004 precursors involving initiating events (as of September 30, 2006).

Event Date	Plant	Description	CCDP
1/23/04	Calvert Cliffs 2	Reactor trip caused by loss of main feedwater and complicated by a failed relay causing overcooling. ***LER 318/04-001***	2×10^{-6}
5/5/04	Dresden 3	Plant-centered LOOP due to breaker malfunction. ***LER 249/04-003***	3×10^{-6}
6/14/04	Palo Verde 1	Grid-related LOOP with offsite power recovery complications due to breaker failure. ***LER 528/04-006***	9×10^{-6}
6/14/04	Palo Verde 2	Grid-related LOOP with an emergency diesel generator unavailable. ***LER 528/04-006***	4×10^{-5}
6/14/04	Palo Verde 3	Grid-related LOOP with offsite power recovery complications due to breaker failure. ***LER 528/04-006***	9×10^{-6}
9/25/04	St. Lucie 1	Severe weather LOOP caused by Hurricane Jeanne while the plant was shut down. ***LER 335/04-004***	1×10^{-5}
9/25/04	St. Lucie 2	Severe weather LOOP caused by Hurricane Jeanne while the plant was shut down. ***LER 335/04-004***	1×10^{-5}

Table 3. FY 2004 precursors involving degraded conditions (as of September 30, 2006).

Event Date[a]	Condition Duration[b]	Plant	Description	ΔCDP
11/3/03	since plant startup	Surry 1	Potential loss of reactor coolant pump (RCP) seal cooling due to postulated fire damage to emergency switchgear. ***LER 280/03-005***	1×10^{-6}
11/3/03	since plant startup	Surry 2	Potential loss of RCP seal cooling due to postulated fire damage to emergency switchgear. ***LER 280/03-005***	1×10^{-6}
1/4/04	720 hours	Brunswick 2	EDG “3” unavailable due to jacket water leak. ***LER 325/04-001***	2×10^{-6}
2/3/04	since plant startup	Turkey Point 3	Triennial fire protection issues. ***LER 251/04-007***	7×10^{-6}
2/3/04	since plant startup	Turkey Point 4	Triennial fire protection issues. ***LER 251/04-007***	7×10^{-6}
2/19/04	61 hours	Palo Verde 2	Failure to implement design of steam generator nozzle dam requiring an extended time in reduced RCS inventory configuration. ***IR 529/04-04, IR 529/04-09***	1×10^{-5}
3/17/04	1117 hours	Peach Bottom 3	High-pressure coolant injection (HPCI) unavailable due to failed flow controller. ***LER 278/04-001***	2×10^{-6}
7/31/04	11 years[c]	Palo Verde 1	Containment sump recirculation potentially inoperable due to pipe voids. ***LER 528/04-009***	4×10^{-5}
7/31/04	11 years[c]	Palo Verde 2	Containment sump recirculation potentially inoperable due to pipe voids. ***LER 528/04-009***	4×10^{-5}
7/31/04	11 years[c]	Palo Verde 3	Containment sump recirculation potentially inoperable due to pipe voids. ***LER 528/04-009***	4×10^{-5}

a. ASP event date is the discovery date for a precursor involving a degraded condition.
b. Condition duration is the time period when the degraded condition existed. The ASP Program limits the analysis exposure time of degraded condition to 1 year.
c. Exact date not given. LER states that condition had existed since 1992 when the new feedwater control system was installed before the power uprate.

Table 4. FY 2005 precursors involving initiating events (as of September 30, 2006).

Event Date	Plant	Description	CCDP
10/10/04	Hope Creek	Manual reactor scram due to moisture separator reheater drain line failure. ***LER 354/04-010***	3×10^{-6}
11/20/04	Vogtle 2	Reactor trip with safety injection and full-open demand from steam bypass valves caused by operator error and failed circuit card. ***LER 425/04-004***	3×10^{-6}
12/10/04	River Bend	Reactor trip due to loss of a non-vital 120V instrument bus. ***LER 458/04-005***	3×10^{-5}
2/22/05	Watts Bar	Low-temperature, over-pressure valve actuations while shut down. ***IR 390/05-03***	7×10^{-6}
4/17/05	Millstone 3	Inadvertent reactor trip and safety injection with failure of turbine-driven AFW pump to start (recoverable). ***LER 423/05-002***	3×10^{-6}
6/23/05	Columbia	Reactor trip due to feedwater pump trip cause by maintenance personnel error. ***LER 397/05-004***	1×10^{-5}
8/29/05	Waterford	Severe weather LOOP caused by Hurricane Katrina while plant was shut down. ***LER 382/05-004***	2×10^{-6}

Table 5. FY 2005 precursors involving degraded conditions (as of September 30, 2006).

Event Date[a]	**Condition Duration**[b]	**Plant**	**Description**	**ΔCDP**
10/19/04	682 hours	Fort Calhoun	EDG 2 inoperable for 28 days due to blown fuse. ***LER 285/04-002***	4×10^{-6}
11/22/04	6024 hours	Watts Bar	Component cooling backup line from essential raw cooling water unavailable due to silt blockage. ***IR 390/04-05***	8×10^{-6}
1/27/05	10 years[c]	Crystal River 3	Single-failure vulnerability of 4160 V engineered safeguard feature (ESF) bus protective relay schemes caused by common power metering circuits. ***LER 302/05-001***	5×10^{-6}
2/2/05	13 years[d]	LaSalle 1	Single-failure vulnerability of 4160 V ESF bus protective relay schemes caused by common power metering circuits. ***LER 373/05-001***	5×10^{-6}
2/2/05	13 years[d]	LaSalle 2	Single-failure vulnerability of 4160 V ESF bus protective relay schemes caused by common power metering circuits. ***LER 373/05-001***	5×10^{-6}
2/11/05	since plant startup	Kewaunee	Several design deficiencies could lead to unavailability of AFW pumps during postulated events (e.g., high-energy line break and tornado). ***LER 305/05-002, LER 305/05-006, LER 305/05-008***	1×10^{-5}
4/27/05	17 days	Indian Point 2	Potential degradation of safety injection system due to nitrogen accumulation from leaking accumulator. ***IR 50-247/05-06***	3×10^{-6}
5/10/05	since plant startup	Kewaunee	Design deficiency could cause unavailability of safety-related equipment during postulated internal flooding. ***LER 305/05-004***	Yellow[e]

a. ASP event date is the discovery date for a precursor involving a degraded condition.
b. Condition duration is the time period when the degraded condition existed. The ASP Program limits the analysis exposure time of degraded condition to 1 year.
c. Exact date not given. LER states that condition had existed since a 1990 design modification.
d. Conditions had existed since design modifications completed on 03/08/91 for Unit 1 and 02/01/92 for Unit 2.
e. The result presented is the final significance determination under the Reactor Oversight Process. Separately, the licensee's numerical estimate was approximately 8×10^{-5}. The staff confirmed that this condition meets the ASP Program threshold of a precursor (i.e., $\Delta CDP \geq 1 \times 10^{-6}$), but does not exceed the threshold of a *significant* precursor (i.e., $\Delta CDP \geq 1 \times 10^{-3}$).

Table 6. *Significant* (CCDP or ΔCDP $\geq 1\times10^{-3}$) accident sequence precursors during the 1969–2005 period in order by event date. *(See notes at the end of table)*

Plant	ΔCDP or CCDP	Date	Description
Davis-Besse	6×10^{-3}	2/27/02	**Multiple conditions coincident with reactor pressure vessel (RPV) head degradation** The analysis included multiple degraded conditions discovered on various dates. These conditions included cracking of CRDM nozzles and RPV head degradation, potential clogging of the emergency sump, and potential degradation of the high-pressure injection (HPI) pumps during recirculation. ***LER 346/02-002***
Catawba 2	2×10^{-3}	2/6/96	**LOOP with an EDG unavailable** When the reactor was at hot shutdown, a transformer in the switchyard shorted out during a storm, causing breakers to open and resulting in a LOOP event. Although both EDGs started, the output breaker of EDG 1B, to essential bus 1B failed to close on demand, leaving bus 1B without AC power. After 2 hours and 25 minutes, operators successfully closed the EDG 1B output breaker. ***LER 414/96-001***
Wolf Creek 1	3×10^{-3}	9/17/94	**Reactor coolant system (RCS) blowdown to refueling water storage tank (RWST)** When the plant was in cold shutdown, operators implemented two unpermitted simultaneous evolutions, which resulted in the transfer of 9,200 gallons (34,825 liters) of RCS inventory to the RWST. Operators immediately diagnosed the problem and terminated the event by closing the residual heat removal (RHR) cross-connect motor-operated valve. The temperature of the RCS increased by 7 °F (4 °C) as a result of this event. ***LER 482/94-013***
Harris 1	6×10^{-3}	4/3/91	**HPI unavailability for one refueling cycle** A degraded condition resulted from relief valve and drain line failures in the alternative minimum flow systems for the charging/safety injection pumps, which would have diverted a significant amount of safety injection flow away from the reactor coolant system. The root cause of the degradation is believed to have been water hammer, as a result of air left in the alternative minimum flow system following system maintenance and test activities. ***LER 400/91-008***
Turkey Point 3	1×10^{-3}	12/27/86	**Turbine load loss with trip; control rod drive (CRD) auto insert fails; manual reactor trip; power-operated relief valve (PORV) sticks open** The reactor was tripped manually following a loss of turbine governor oil system pressure and the subsequent rapid electrical load decrease. Control rods failed to insert automatically because of two cold solder joints in the power mismatch circuit. During the transient, a PORV opened but failed to close (the block valve had to be closed). The loss of governor oil pressure was the result of a cleared orifice blockage and the auxiliary governor dumping control oil. ***LER 250/86-039***

Plant	ΔCDP or CCDP	Date	Description
Catawba 1	3×10^{-3}	6/13/86	**Chemical and volume control system (CVCS) leak (130 gpm) from the component cooling water (CCW)/CVCS heat exchanger joint (i.e., small-break loss-of-coolant accident (LOCA))** A weld break on the letdown piping, near the CCW/CVCS heat exchanger caused excessive RCS leakage. A loss of motor control center power caused the variable letdown orifice to fail open. The weld on the 1-inch (2.54-cm) outlet flange on the variable letdown orifice failed as a result of excessive cavitation-induced vibration. This event was a small-break LOCA. ***LER 413/86-031***
Davis-Besse	1×10^{-2}	6/9/85	**Loss of feedwater; scram; operator error fails AFW; PORV fails open** While at 90-percent power, the reactor tripped with main feedwater (MFW) pump 1 tripped and MFW pump 2 unavailable. Operators made an error in initiating the steam and feedwater rupture control system and isolated EFW to both steam generators (SGs). The PORV actuated three times and did not reseat at the proper RCS pressure. Operators closed the PORV block valves, recovered EFW locally, and used HPI pump 1 to reduce RCS pressure. ***LER 346/85-013***
Hatch 1	2×10^{-3}	5/15/85	**Heating, ventilation, and air conditioning (HVAC) water shorts panel; safety relief valve (SRV) fails open; HPCI fails; reactor core isolation cooling (RCIC) unavailable** Water from an HVAC vent fell onto an analog transmitter trip system panel in the control room (the water was from the control room HVAC filter deluge system which had been inadvertently activated as a result of unrelated maintenance activities). This resulted in the lifting of the SRV four times. The SRV stuck open on the fourth cycle, initiating a transient. Moisture also energized the HPCI trip solenoid making HPCI inoperable. RCIC was unavailable due to maintenance. ***LER 321/85-018***
Lasalle 1	2×10^{-3}	9/21/84	**Operator error causes scram; RCIC unavailable; RHR unavailable** While at 23-percent power, an operator error caused a reactor scram and main steam isolation valve (MSIV) closure. RCIC was found to be unavailable during testing (one RCIC pump was isolated, and the other pump tripped during the test). RHR was found to be unavailable during testing because of an inboard suction isolation valve failing to open on demand. Both RHR and RCIC may have been unavailable after the reactor scram. ***LER 373/84-054***
Salem 1	5×10^{-3}	2/25/83	**Trip with automatic reactor trip capability failed** When the reactor was at 25-percent power, both reactor trip breakers failed to open on demand of a low-low SG level trip signal. A manual trip was initiated approximately 3 seconds after the automatic trip breaker failed to open, and was successful. The same event occurred 3 days later, at 12-percent power. Mechanical binding of the latch mechanism in the breaker under-voltage trip attachment failed both breakers in both events. ***LER 272/83-011***

Plant	ΔCDP or CCDP	Date	Description
Davis-Besse	$2{\times}10^{-3}$	6/24/81	**Loss of vital bus; failure of an EFW pump; main steam safety valve lifted and failed to reseat** With the plant at 74-percent power, the loss of bus E2 occurred because of a maintenance error during CRDM breaker logic testing. A reactor trip occurred, due to loss of CRDM power (bus E2), and instrumentation power was also lost (bus E2 and a defective logic card on the alternate source). During the recovery, EFW pump 2 failed to start because of a maladjusted governor slip clutch and bent low speed stop pin. A main steam safety valve lifted, and failed to reseat (valve was then gagged). ***LER 346/81-037***
Brunswick 1	$7{\times}10^{-3}$	4/19/81	**RHR heat exchanger damaged** While the reactor was in cold shutdown during a maintenance outage, the normal decay heat removal system was lost because of a failure of the single RHR heat exchanger that was currently in service. The failure occurred when the starting of a second RHR service water pump caused the failure of a baffle in the waterbox of the RHR heat exchanger, thereby allowing cooling water to bypass the tube bundle. The redundant heat exchanger was inoperable because maintenance was in progress. ***LER 325/81-032***
Millstone 2	$5{\times}10^{-3}$	1/2/81	**Loss of DC power and one EDG as a result of operator error; partial LOOP** When the reactor was at full power, the 125 V DC emergency bus was lost as a result of operator error. The loss of the bus caused the reactor to trip, but the turbine failed to trip because of the unavailability of DC bus A. Loads were not switched to the reserve transformer (following the manual turbine trip) because of the loss of DC bus A. Two breakers (on the B 6.9 kV and 4.16 kV busses) remained open, thereby causing a LOOP. EDG B tripped as a result of leakage of the service water flange, which also caused the B 4.16 kV bus to be de-energized. An operator recognition error caused the PORV to be opened at 2380 psia. ***LER 336/81-005***
St. Lucie 1	$1{\times}10^{-3}$	6/11/80	**Reactor coolant pump seal LOCA due to loss of CCW; top vessel head bubble** At 100-percent power, a moisture-induced short circuit in a solenoid valve caused a CCW containment isolation valve to shut causing loss of CCW to all RCPs. While pressure was reduced to initiate the shutdown cooling system (SCS), the top head water flashed to steam, thus forming a bubble (initially undetected by the operators). During the cooldown, the SCS relief valves lifted and low-pressure safety injection (LPSI) initiated (i.e., one LPSI pump started charging, while the other was used for cooldown). ***LER 335/80-029***
Davis-Besse	$1{\times}10^{-3}$	4/19/80	**Loss of two essential busses** When the reactor was in cold shutdown, two essential busses were lost because of breaker ground fault relay actuation during an electrical lineup. The decay heat drop line valve was shut, and air was drawn into the suction of the decay heat removal pumps, resulting in loss of a decay heat removal path. ***LER 346/80-029***

Plant	ΔCDP or CCDP	Date	Description
Crystal River 3	5×10^{-3}	2/26/80	**Loss of 24-V DC power to non-nuclear instrumentation (NNI)** The 24-V power supply to the NNI was lost as a result of a short to ground. This initiated a sequence of events in which the PORV opened (and stayed open) as a direct result of the loss of the NNI power supply. HPI initiated as a result of depressurization through the open PORV, and with approximately 70 percent of NNI inoperable or inaccurate, the operator correctly decided that there was insufficient information available to justify terminating HPI. Therefore, the pressurizer was pumped solid, one safety valve lifted, and flow through the safety valve was sufficient to rupture the reactor coolant drain tank rupture disk, thereby spilling approximately 43,000 gallons (162,800 liters) of primary water into the containment. ***LER 302/80-010***
Hatch 2	1×10^{-3}	6/3/79	**Loss of feedwater; HPCI fails to start; RCIC is unavailable** During a power increase, the reactor tripped because a condensate system trip. HPCI failed to initiate on low-low level due to a failed turbine stop valve. In addition, water from leaking mechanical seal lines and an unknown valve caused water to back up and contaminate the pump oil. RCIC was out of service for unspecified reasons. ***LER 366/79-045***
Oyster Creek	2×10^{-3}	5/2/79	**Loss of feedwater flow** During testing of the isolation condenser, a reactor scram occurred. The feedwater pump tripped and failed to restart. The recirculation pump inlet valves were closed. The isolation condenser was used during cooldown. ***LER 219/79-014***
Three Mile Island 2	1	3/28/79	**Loss of feedwater; PORV failed open; operator errors led to core damage** Operators misinterpreted plant conditions, including the RCS inventory, during a transient that was triggered by a loss of feedwater and a stuck-open PORV. As a result, the operators prematurely shut off the high-pressure safety injection system, turned off the reactor coolant pumps, and failed to diagnose and isolate a stuck-open pressurizer relief valve. With no RCS inventory makeup, the core became uncovered and fuel damage occurred. In addition, contaminated water was spilled into the containment and auxiliary buildings. ***LER 320/79-012***
Salem 1	1×10^{-2}	11/27/78	**Loss of vital bus and scram; multiple components lost** While the reactor was at 100-percent power, vital instrument bus 1B was lost as a result of the failure of an output transformer and two regulating resistors. Loss of the vital bus caused a false low RCS loop flow signal, thereby causing a reactor trip. Two EFW pumps failed to start (one because of the loss of vital bus 1B, and the other because of a maladjustment of the over-speed trip mechanism). Inadvertent safety injection occurred as a result of decreasing average coolant temperature and safety injection signals. ***LER 272/78-073***
Calvert Cliffs 1	3×10^{-3}	4/13/78	**LOOP; one EDG failed to start** With the plant shut down, a protective relay automatically opened the switchyard breakers, resulting in a LOOP. EDG 11 failed to start. EDG 22 started and supplied the safety busses. ***LER 317/78-020***

Plant	ΔCDP or CCDP	Date	Description
Farley 1	5×10^{-3}	3/25/78	**Low-Low water level in one SG trip/scram; turbine-driven EFW pump fails** A low-level condition in a single SG resulted in a reactor trip. The turbine-driven EFW pump failed to start. Both motor-driven EFW pumps started, but were deemed ineffective because all recirculation bypass valves were open (thereby diverting flow). A recirculation valve was manually closed. ***LER 348/78-021***
Rancho Seco	1×10^{-1}	3/20/78	**Failure of NNI and steam generator dryout** When the reactor was at power, a failure of the NNI power supply resulted in a loss of main feedwater, which caused a reactor trip. Because instrumentation drift falsely indicated that the steam generator contained enough water, control room operators did not act promptly to open the EFW flow control valves to establish secondary heat removal. This resulted in steam generator dryout. ***LER 312/78-001***
Davis-Besse	5×10^{-3}	12/11/77	**EFW pumps inoperable during test** During EFW pump testing, operators found that control over both pumps was lost because of mechanical binding in the governor of one pump and blown control power supply fuses for the speed changer motor on the other pump. ***LER 346/77-110***
Davis-Besse	7×10^{-2}	9/24/77	**Stuck-open pressurizer PORV** A spurious half-trip of the steam and feedwater rupture control system initiated closure of the startup feedwater valve. This resulted in reduced water level in SG 2. The pressurizer PORV lifted nine times and then stuck open because of rapid cycling. ***LER 346/77-016***
Cooper	1×10^{-3}	8/31/77	**Partial loss of feedwater; reactor scram; RCIC and HPCI degraded** A blown fuse caused the normal power supply to the feedwater and RCIC controllers to fail. The alternate power supply was unavailable because of an unrelated fault. A partial loss of feedwater occurred, and the reactor tripped on low water level. RCIC and HPCI operated, however, both pumps did not accelerate to full speed (RCIC because of the failed power supply and HPCI because of a failed governor actuator). ***LER 298/77-040***
Zion 2	2×10^{-3}	7/12/77	**Testing causes instrumentation errors** With the reactor in hot shutdown, testing caused operators to lose indications of reactor and secondary system parameters. In addition, inaccurate inputs were provided to control and protection systems. ***LER 304/77-044***
Millstone 2	1×10^{-2}	7/20/76	**LOOP from grid disturbance; errors in EDG loading fail the ECCS** With the reactor at power, a main circulating water pump was started, which resulted in an in-plant voltage reduction to below the revised trip set point. This isolated the safety-related busses and started the EDGs. Each time a major load was tied onto the diesel, the revised under-voltage trip set points tripped the load. As a result, at the end of the EDG loading sequence, all major loads were isolated, even though the EDGs were tied to the safety-related busses. ***LER 336/76-042***

Plant	ΔCDP or CCDP	Date	Description
Kewaunee	5×10^{-3}	11/5/75	**Inoperable EFW pumps during startup as a result of leaks from the demineralizer into the condensate storage tank (CST)** Mixed bed resin beads were leaking from the demineralizer in the makeup water system and migrated to the CST. As a result, during startup, both motor-driven EFW pump suction strainers became clogged, thereby resulting in low pump flow. The same condition occurred for the turbine-driven EFW pump suction strainer. ***LER 305/75-020***
Brunswick 2	9×10^{-3}	4/29/75	**Multiple valve failures; RCIC inoperable as a result of stuck-open down/safety valve** At 10-percent power, the RCIC system was determined to be inoperable, and SRV B was stuck open. The operator failed to scram the reactor according to the emergency operating procedures (EOPs). The HPCI system failed to run and was manually shut down as a result of high torus level. Loop B of RHR failed as a result of a failed service water supply valve to the heat exchanger. The reactor experienced an automatic scram on manual closure of the MSIV. ***LER 324/75-013***
Browns Ferry 1	2×10^{-1}	3/22/75	**Cable tray fire** The fire was started by an engineer, who was using a candle to check for air leaks through a firewall penetration seal to the reactor building. The fire resulted in significant damage to cables related to the control of Units 1 and 2. All Unit 1 ECCS were lost, as was the capability to monitor core power. Unit 1 was manually shut down and cooled using remote manual relief valve operation, the condensate booster pump, and control rod drive system pumps. Unit 2 was shut down and cooled for the first hour by the RCIC system. After depressurization, Unit 2 was placed in the RHR shutdown cooling mode with makeup water available from the condensate booster pump and control rod drive system pump. ***LER 259/75-006***
Turkey Point 3	2×10^{-2}	5/8/74	**Failure of three EFW pumps to start during test** Operators attempted to start all three EFW pumps while the reactor was at power for testing. Two of the pumps failed to start as a result of over-tightened packing. The third pump failed to start because of a malfunction in the turbine regulating valve pneumatic controller. ***LER 250/74-LTR***
Point Beach 1	5×10^{-3}	4/7/74	**Inoperable EFW pumps during shutdown** While the reactor was in cooldown mode, motor-driven EFW pump A did not provide adequate flow. The operators were unaware that the in-line suction strainers were 95 percent plugged (both motor-driven pumps A and B). A partially plugged strainer was found in each of the suction lines for both turbine-driven EFW pumps. ***LER 266/74-LTR***
Point Beach 1	1×10^{-3}	1/12/71	**Failure of containment sump valves** During a routine check of the containment tendon access gallery, air was observed leaking from the packing of one sump isolation valve. Operators attempted to open the valve, but the valve failed to open because of a shorted solenoid in the hydraulic positioner. The redundant sump isolation valve was also found inoperable because of a stuck solenoid in the hydraulic positioner. ***LER 266/71-LTR***

NOTES:

- Events are selected on the basis of CCDPs, as estimated by the ASP Program.
- Because of model and data uncertainties, it is difficult to differentiate between events with CCDPs that are within a factor of about 3.
- ASP analyses have been performed since 1969, and the associated methodologies and PRA models have evolved over the past 35 years. Consequently, the results obtained in the earlier years may be conservative when compared to those obtained using the current methodology and PRA models.

Table 7. Precursors involving failure modes and event initiators that were not explicitly modeled in the PRA or IPE concerning the specific plant at which the precursor event occurred.

Plant	Year	Event Description
Kewaunee	2005	Design deficiency could cause unavailability of safety-related equipment during postulated internal flooding. ***LER 305/05-004***
LaSalle 1 & 2 Crystal River 3	2005	Single-failure vulnerability of 4160 V ESF bus protective relay schemes caused by common power metering circuits. ***LER 302/05-001, LER 373/05-001***
Watts Bar	2005	Component cooling backup line from essential raw cooling water was unavailable because silt blockage. ***IR 390/04-05***
Watts Bar	2005	Low-temperature, over-pressure valve actuations while shut down. ***IR 390/05-03***
Calvert Cliffs 2	2004	Failed relay causes overcooling condition during reactor trip. ***LER 318/04-001***
Palo Verde 1, 2, & 3	2004	Containment sump recirculation potentially inoperable because of pipe voids. ***LER 528/04-009***
Shearon Harris 1	2003	Postulated fire could cause the actuation of certain valves which could result in a loss of the charging pump, RCP seal cooling, loss of RCS inventory, and other conditions. ***LER 400/02-004***
St. Lucie 2	2003	RPV head leakage because of cracking of CRDM nozzles. ***LER 389/03-002***
Crystal River 3 Three Mile Island 1 Surry 1 North Anna 1 & 2	2002	RPV head leakage because of cracking of CRDM nozzle(s). ***LER 302/01-004, LER 289/01-002, LER 280/01-003, LER 339/01-003, LER 339/02-001***
Columbia 2	2002	Common-cause failure of breakers used in four safety-related systems. ***IR 397/02-05***
Davis-Besse	2002	Cracking of CRDM nozzles and RPV head degradation, potential clogging of the emergency sump, and potential degradation of the HPI pumps. ***LER 346/02-002***
Callaway	2002	Potential common-mode failure of all AFW pumps because of foreign material in the CST caused by degradation of the floating bladder. ***LER 483/01-002***
Point Beach 1 & 2	2002	Potential common-mode failure of all auxiliary feedwater (EFW) pumps because of a design deficiency in the EFW pumps' air-operated minimum flow recirculation valves. The valves fail closed on loss of instrument air, which could potentially lead to pump deadhead conditions and a common mode, non-recoverable failure of the EFW pumps. ***LER 266/01-005***
Harris	2002	Potential failure of RHR pump A and containment spray pump A because of debris in the pumps' suction lines. ***LER 400/01-003***
Oconee 1, 2, & 3 Arkansas 1 Palisades	2001	RPV head leakage because of cracking of CRDM nozzle(s). ***LER 269/00-006, LER 269/02-003, LER 269/03-002, LER 270/01-002, LER 270/02-002, LER 287/01-001 , LER 287/01-003, LER 287/03-001, LER 313/01-002, LER 313/02-003, LER 255/01-002, LER 255/01-004***
Kewaunee	2001	Failure to provide a fixed fire suppression system could result in a postulated fire that propagates and causes the loss of control cables in both safe-shutdown trains. ***IR 305/02-06***
Prairie Island 1 & 2	2000	A 1988 change in the backwash system for the cooling water pump drive shaft bearing lubrication water supply system could result in loss of plant cooling water during postulated LOOP conditions. ***LER 282/00-004***

Plant	Year	Event Description
Oconee 1, 2, & 3	2000	Non-seismic 16-inch fire system piping header transited through the auxiliary building and posed a potential flooding problem should the piping rupture during a seismic event. ***IR 269/00-08***
Cook 1 & 2	1999	Postulated high-energy line leaks or breaks in turbine building leading to failure of multiple safety-related equipment. ***LER 315/99-026***
Oconee 1, 2, & 3	1999	Postulated high-energy line leaks or breaks in turbine building leading to failure of safety-related 4 kV switchgear. ***LER 269/99-001***
Cook 2	1998	Postulated high-energy line break in turbine building leading to failure of all CCW pumps. ***LER 316/98-005***
Oconee 1, 2, & 3	1998	Incorrect calibration of the borated water storage tank (BWST) level instruments resulting in a situation where the (EOP requirements for BWST-to-reactor building emergency sump transfer would never have been met; operators would have been working outside the EOP. ***LER 269/98-004***
Haddam Neck	1996	Potentially inadequate RHR pump net positive suction head following a large- or medium-break LOCA because of design errors. ***LER 213/96-016***
LaSalle 1 & 2	1996	Fouling of the cooling water systems because concrete sealant injected into the service water tunnel. ***LER 373/96-007***
Wolf Creek	1996	Reactor trip with the loss of one train of emergency service water because of the formation of frazil ice on the circulating water traveling screens with concurrent unavailability of the turbine-driven AFW pump. ***LER 482/96-001***

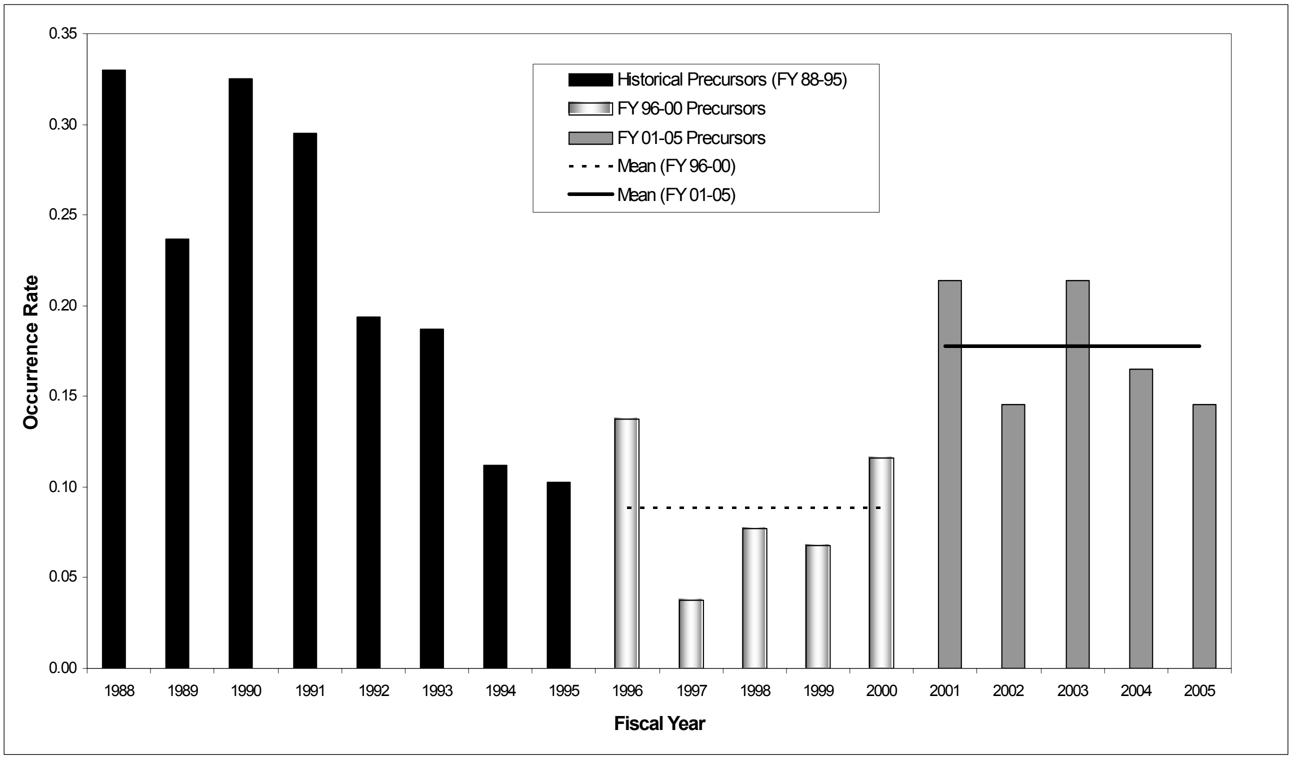

Figure 1: Total Precursors– occurrence rate, by fiscal year. Data for FY 1988 through FY 1995 are shown for historical perspective. Data from FY 2001 through FY 2005 represent the period with an increased ASP scope. No statistically significant trend (p-value = 0.8608) is detected during the FY 2001–2005 period. Data from FY 1996 through 2000 are charted separately since it is part of the data from within the last 10 years without the increase in ASP scope. No statistically significant trend (p-value = 0.3735) is detected during the FY 1996–2000 period.

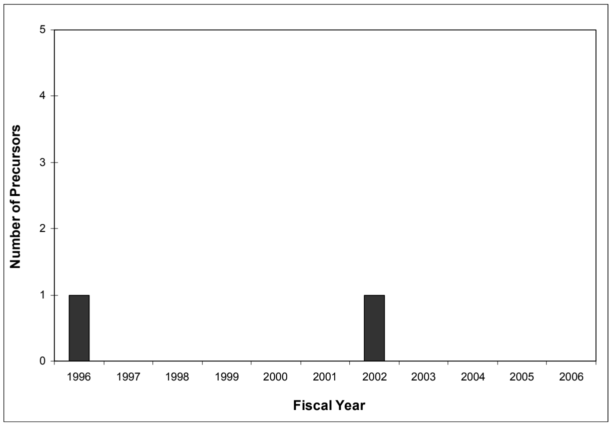

Figure 2: *Significant* precursors (CCDP or ΔCDP ≥10^{-3})– number of precursors, by fiscal year. No trend line is shown because no trend is detected that is statistically significant (p-value = 0.4677).

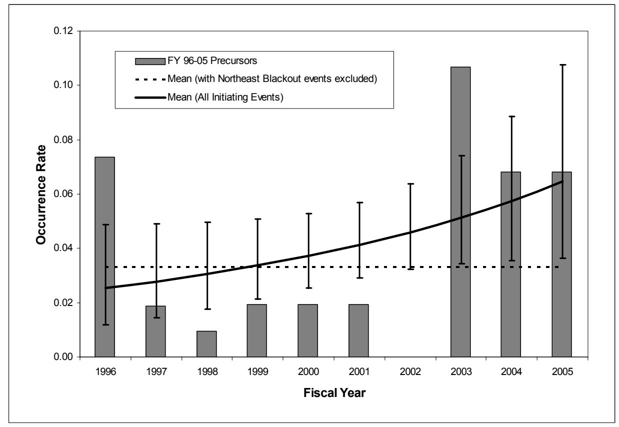

Figure 3: Precursors involving initiating events– occurrence rate, by fiscal year. The increasing trend is statistically significant (0.0489). No statistically significant trend (p-value = 0.3303) is detected when the 2003 Northeast blackout events are excluded.

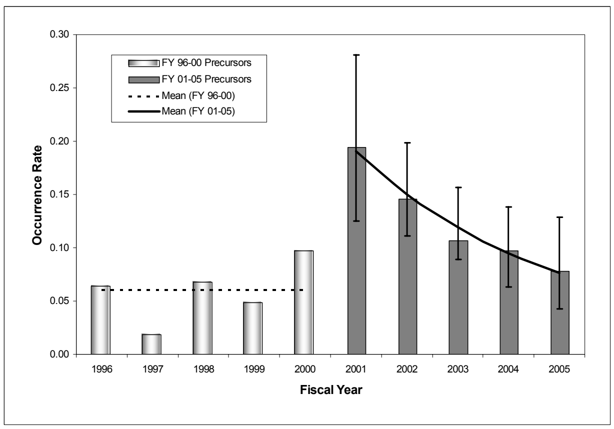

Figure 4: Precursors involving degraded conditions– occurrence rate, by fiscal year. A statistically significant decreasing trend (p-value = 0.0099) is detected during the FY 2001–2005 period of increased ASP scope. No statistically significant trend (p-value = 0.2100) is detected during the period without the increase in ASP scope (FY 1996–2000).

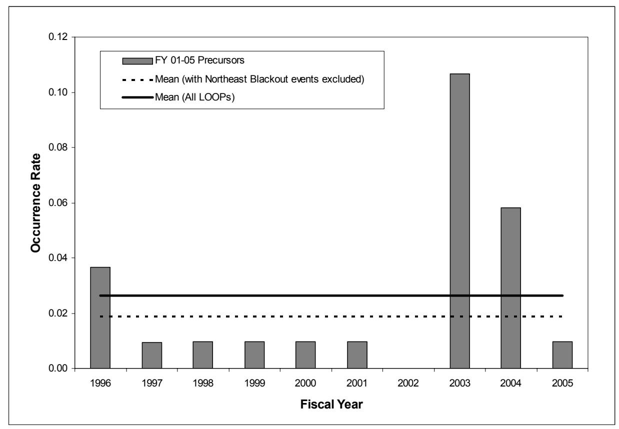

Figure 5: Precursors involving loss of offsite power events– occurrence rate, by fiscal year. No statistically significant trend (p-value = 0.0551) is detected during the FY 1996–2005 period. No statistically significant trend (p-value = 0.5109) is detected when the 2003 Northeast blackout events were excluded.

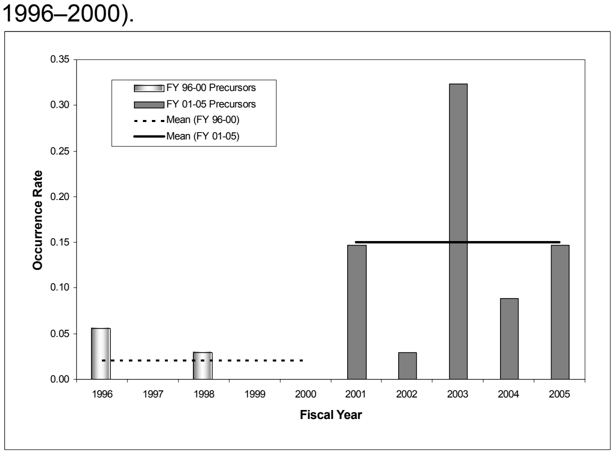

Figure 6: Precursors involving BWRs– occurrence rate, by fiscal year. No statistically significant trend (p-value = 0.0904) is detected during the FY 2001–2005 period of increased ASP scope. No statistically significant increasing trend (p-value = 0.7773) is detected during the period without the increase in ASP scope (FY1996–2000).

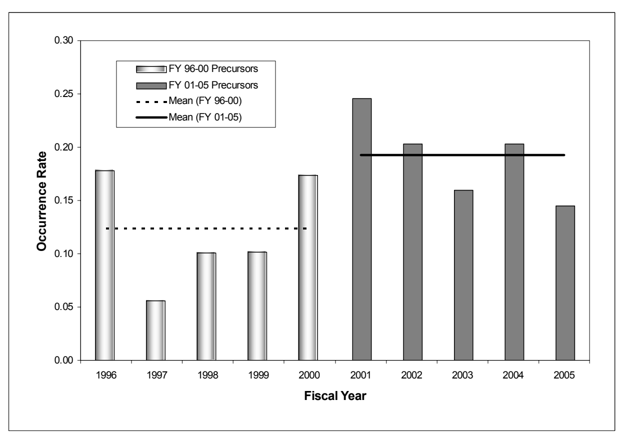

Figure 7: Precursors involving PWRs– occurrence rate, by fiscal year. No statistically significant trend (p-value = 0.8111) is detected during the FY 2001–2005 period of increased ASP scope. No statistically significant trend (p-value = 0.2225) is detected during the period without the increase in ASP scope (FY 1996–2000).

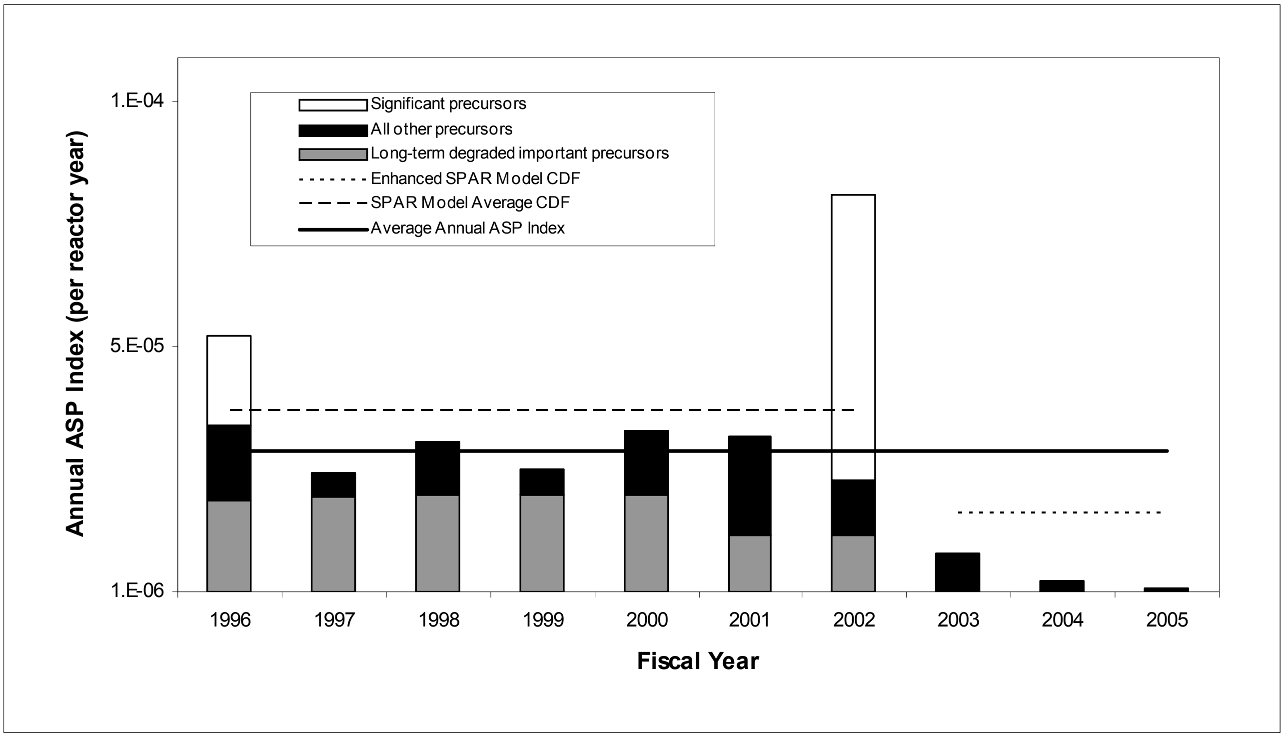

Figure 8: Integrated ASP Index– risk contribution from precursors, per fiscal year. The risk contribution from precursors involving degraded conditions is included in all fiscal years when the degraded condition existed. The risk contribution from precursors involving initiating events is included only in the fiscal year in which the event occurred.

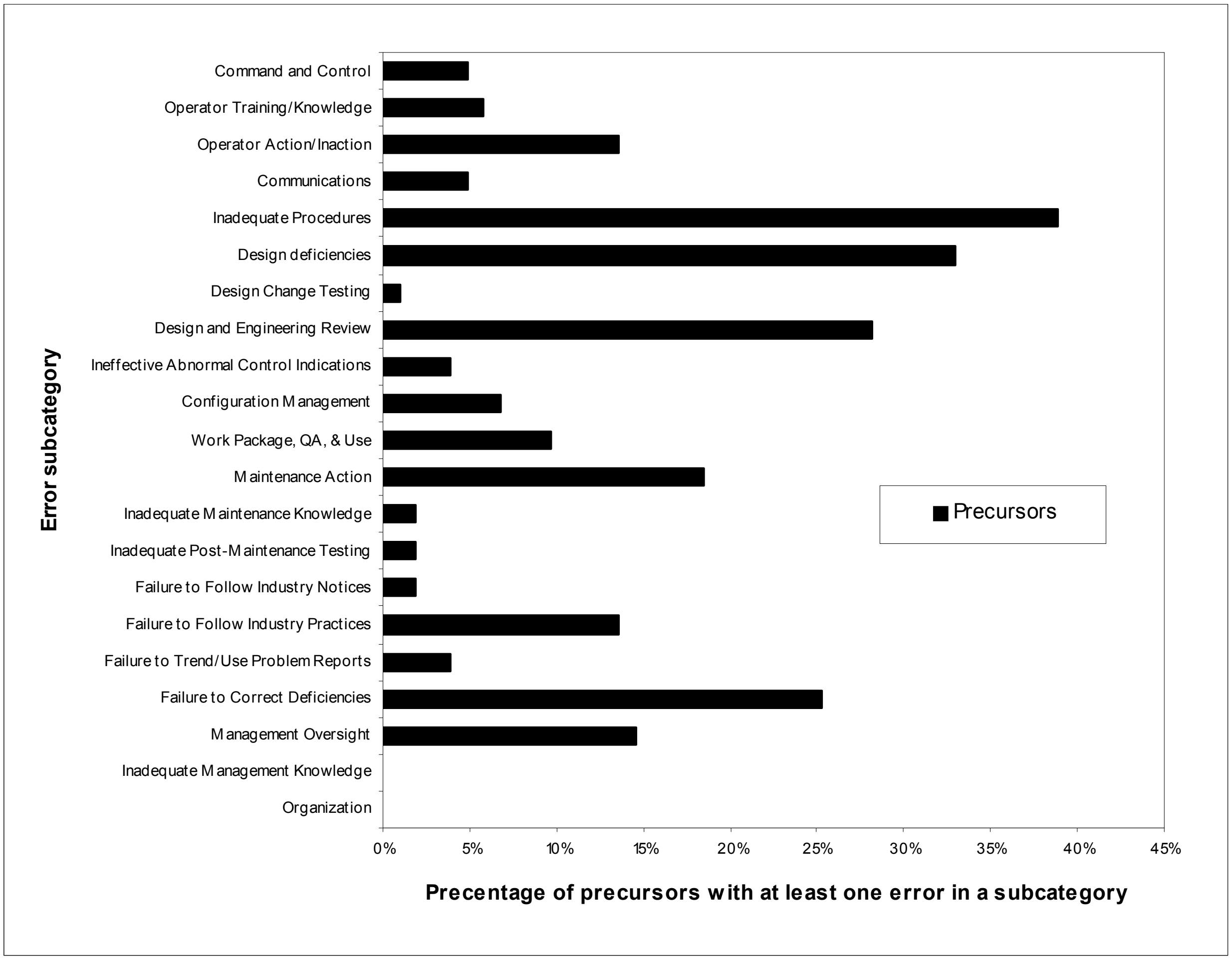

Figure 9: Percentage of precursors with at least one error in an error subcategory.

Standardized Plant Analysis Risk Model and Other Probabilistic Risk Assessment Lessons Learned from Mitigating Systems Performance Index Development and Implementation

1.0 Introduction

The Standardized Plant Analysis Risk (SPAR) Model Development Program has played an integral role in the Accident Sequence Precursor (ASP) Program analysis of operating events. In a complementary fashion, one of the objectives of the ASP Program is to use plant operating experience results and insights for feedback to the SPAR models, as well as to licensee probabilistic risk assessment (PRA) models. In addition, the use of SPAR models as part of the ASP Program and the significance determination process (SDP) Phase 3 evaluations also provides the opportunity for review and benchmarking of the SPAR models against the licensee PRA models in cases where the licensee also provides risk-related input to the ASP and SDP evaluations.

In a similar manner, over the past year, as part of the NRC's efforts to implement the Mitigating Systems Performance Index (MSPI), the staff used SPAR models as a tool to help determine and verify the quality of PRAs needed for MSPI implementation. This MSPI PRA quality task provided many lessons learned in terms of modeling and data found in the SPAR models and in licensee PRA models. This enclosure summarizes these lessons learned.

2.0 Background

The MSPI is formulated as a simplified linear approximation of the change in core damage frequency (CDF) attributable to changes in the reliability and availability of risk-significant elements of a plant system in response to internal initiating events with the reactor operating at power. The Birnbaum *importance* of a basic event is the partial derivative of the CDF with respect to the basic event probability in a PRA model and provides a measure of the risk sensitivity of a plant component to CDF.

The Birnbaum importance measures of the monitored components are critical inputs to the MSPI calculation, and each licensee determines its measures by using its PRA model. An important aspect of PRA quality for MSPI implementation is the comparison of Birnbaum values within different classes of plant design. The Birnbaum values for like components modeled in the PRAs for two plants of similar design should be relatively close. For example, two four-loop pressurized-water reactors (PWRs) of the same thermal rating, with similar numbers and ratings of emergency diesel generators, auxiliary feedwater system pumps, and emergency core cooling system components, should generally have Birnbaum values for like components that agree to within about a factor of 3 based on previous staff reviews. Greater differences can be attributable to the following:

- Important differences in balance-of-plant design, particularly electrical power and cooling water dependencies, or plant backfits can result in two otherwise similar plant designs having divergent values.

- Differences in operating procedures and plant equipment performance may occur because some plants may have implemented off-normal or emergency operating procedures to address risk-significant scenarios. In other cases, the plant equipment performances might differ, and these are reflected in differing PRA model inputs and outputs.

- Finally, PRA modeling assumptions and methods may differ. Two different organizations may have prepared the PRA models for two sister plants and used different software and databases and/or different levels of detail in their modeling.

In this regard, the SPAR models representing all 103 operating plants have proven useful in establishing a benchmark for this effort. Because the SPAR models use identical industry-average failure rates and similar modeling techniques, two of the three elements contributing to differences in plant Birnbaum values can be eliminated. Theoretically, any differences that exist for Birnbaum values for like components in a group of sister plants would arise from differences in plant design. In many cases, very subtle differences such as the direct current (DC) power dependencies or the installation of a nonsafety pump can account for an order of magnitude or more difference in Birnbaum values.

3.0 Use of SPAR Models to Address PRA Quality in MSPI

The staff used the SPAR models as part of its review of the technical adequacy of the licensee PRA models for implementation of the MSPI in FY 2006. The staff obtained PRA information from the industry in the form of Birnbaum importance measures at the basic-event level from the draft MSPI basis documents provided by the licensees in September 2005. The staff assigned plants to SPAR groups based on specific design characteristics. Plant PRA model Birnbaums were then compared to the Birnbaums of the SPAR group. If the Birnbaums were comparable, the staff eliminated the plant PRA model component as a possible outlier. If not comparable, the staff then reevaluated each candidate outlier to determine if the basic event was in the appropriate group. Basic event Birnbaums were reassigned to different groups as appropriate and the process repeated. The staff then evaluated the remaining plant components that could not be eliminated by the above screening against the following three criteria:

- Was the Birnbaum different because of an identifiable design feature?
- Was the Birnbaum different because of an identifiable operations feature (data, procedure)?
- Was the Birnbaum different because of an identifiable modeling method difference?

The review encompassed design features, operations features, or modeling method, as appropriate. If the modeling or method was acceptable to the staff, it eliminated the basic event as a possible outlier. In addition, the staff used the industry's own PRA cross-comparison efforts, in the form of Westinghouse Owners Group (WOG) and Boiling Water Reactors Owners Group (BWROG) reports (References 2 and 3), to attempt to address candidate outliers. If the information available to the NRC reviewers was not adequate to explain the outlier issue, the staff usually contacted the licensee in an effort to resolve the issue. Those candidate outliers that could not be resolved by this review effort were then characterized as final outliers.

For each final outlier, the staff contacted the licensee and explained why the staff believed the plant PRA value was an outlier. Each licensee had an opportunity to resolve the concern. Often, this involved performing PRA model sensitivity studies, providing relevant procedures and data, or providing relevant PRA model calculations. The staff continued to work with the industry until all MSPI outlier concerns were resolved, either by the staff's acceptance of the reason for the Birnbaum value difference, or by the licensee changing its PRA model. Various plants made over one dozen PRA model changes as a result of this comprehensive review effort. In addition, the SPAR models were changed, in part to address needed enhancements identified in the outlier review process.

4.0 SPAR Model Changes

A number of changes to the SPAR models have been or are being implemented as a result of the MSPI PRA outlier identification and resolution process. In most cases, these same issues had been identified as part of the overall SPAR model enhancement effort, and were being implemented one plant model at a time consistent with previously planned model updates. The following describes some of the more significant SPAR modeling issues that arose during the PRA outlier resolution process.

Loss of vital alternating current (AC) bus frequency. During the review of a number of candidate outliers for auxiliary/emergency feedwater pumps for PWRs, the staff found that the loss of AC bus (with no recovery) frequency used in the SPAR model was significantly higher than that used by most of the industry. This manifested itself in Birnbaum importance values for such pumps being much higher in the SPAR model than in the licensees' PRAs. In its review of the operating events database used for SPAR, the staff found that 75 percent of the original events listed were not applicable and should be eliminated from the data, and that the loss of vital AC bus frequency should decrease by about a half order of magnitude. The staff is incorporating these changes into the SPAR models as it updates each model.

Loss of vital DC bus frequency. Similar to the preceding issue regarding the loss of vital AC bus frequency, staff reviews identified that the loss of vital DC bus (with no recovery) frequency in the SPAR models was significantly higher than that used by most of the industry. Review of the operating events database used for SPAR found that two out of three of the original events listed should be eliminated from the data, and that the loss of vital DC bus frequency should decrease by about a half order of magnitude. The staff is incorporating these changes into the SPAR models as it updates each model.

Loss of vital electrical bus event modeling. During the process of addressing PRA candidate outliers, the staff identified asymmetries in the Birnbaum values for some pumps both within the SPAR models and within the licensees' PRA models. For example, the Birnbaum value for the emergency feedwater pump on one safety train might be high, while the value for the opposite train was low. In some cases, the asymmetry represented real plant design asymmetry regarding power supply dependencies. In other cases, this asymmetry was an artifact of the method the licensee used to model test and maintenance unavailability. In still other cases, the SPAR model used the simplifying approach of modeling the loss of only one electrical division, usually the more important division, while doubling the frequency as appropriate. This modeling assumption manifested itself in incorrect Birnbaum values for some key components in the SPAR models. The staff is changing the SPAR models to explicitly treat the loss of each risk-significant electrical bus separately, as appropriate.

Single loss-of-service-water frequency value for all sites. The SPAR models use a single, operating experience-based value for the total loss-of-service- water frequency at all plants irrespective of plant design and site characteristics, e.g., ocean site versus inland river location with cooling towers. However, during its reviews, the staff noted significant site-to-site variations for loss-of-service- water frequency used in licensee PRAs. As a consequence, the staff has initiated a task to identify the feasibility and data needs for developing site-specific frequencies for loss of service water. If successful, this effort may lead to the development of plant-specific initiator fault trees for events such as loss of service water, loss of component cooling water, and loss of instrument air.

In addition to the above anticipated model changes, the SPAR Model Development Program will address a number of long outstanding issues. Many of these issues became evident during the MSPI PRA outlier identification and resolution process. Examples include the following:

- the need to perform confirmatory thermal-hydraulic (T-H) analyses in support of system success criteria that differ from the standard set in the SPAR models, e.g., number of pressurizer power-operated relief valves (PORVs) needed for bleed and feed success in PWRs

- development of a standard approach for recovery from station blackout after battery depletion

- development of a standard approach for modeling BWR reactor vessel injection following gradual containment overpressurization owing to loss of suppression pool cooling

The staff has identified the need for extensive T-H analyses in a number of areas to provide more solid technical bases for success criteria and operator action timing, consistent with requirements set forth in the American Society of Mechanical Engineers (ASME) PRA standard (Reference 1), for example. As part of the Risk Assessment Standardization Project (refer to Enclosure 1 for details about RASP), the staff is developing a multiyear plan and schedule. This work plan will be completed in FY 2007.

5.0 Licensee PRA Model Issues

During the MSPI PRA outlier resolution process, the staff identified a number of common issues in some of the licensees' PRA models. In conjunction with the licensees, the staff ultimately resolved most of these issues. The following describes several of the more important issues that were frequently observed.

Loss of offsite power (LOOP) issues. The PRA outlier screening process identified a number of emergency diesel generator (EDG) Birnbaum values from the licensees' PRAs that appeared low compared to those within the industry plant group, or compared to the SPAR model values. Most of these issues related in some form to one or more of the following:

- the application of convolution integrals for assessing more accurately the timing of equipment failures and the impact on offsite power recovery

- low contribution from one or two components to the total LOOP frequency, e.g., weather-related or grid-related

- the treatment of alternate power supplies as partially or totally independent from the LOOP events in the data, e.g., 161-kV or 69-kV emergency power source

The staff obtained and reviewed several detailed offsite power recovery calculations using convolution integrals. In most cases, the net effect of these analyses is to reduce the contribution of LOOP/station blackout sequences to CDF. The reduction is a function of the degree of redundancy of emergency power supplies, the number and diversity of equipment available for coping with the station blackout event, and critical timing issues such as core uncovery and battery depletion. The staff found the analyses to be acceptable and was able to resolve several PRA outlier issues.

The LOOP frequency comprises several elements. While there are plant-to-plant variations in the modeling of LOOP events, generally the elements consist of grid-related, plant-centered-related, and severe weather-related components. In several cases, the staff determined that the licensee's model had not included the weather-related component as is accepted practice for most PRAs, and the licensee agreed to incorporate that component. In several other cases, the licensee used a grid-related component lower than the norm because that plant's geographic location makes it less susceptible to grid-related events, as most grid-related events tend to occur in the Northeast. The staff generally found the analyses to be reasonable in this regard. In at least one case, the PRA model for a plant in the Northeast revised its PRA model to reflect a higher contribution of grid-related events, based on regional operating experience data.

Finally, a number of plant PRA models had LOOP frequencies substantially lower than the norm based on quantitative credit taken for alternate or emergency offsite power supplies from 161-kV or 69-kV lines, for example. The staff agreed that such alternate power supplies provided a safety benefit. However, the staff's concern was with how the LOOP data were being applied within the PRA model in question. The LOOP data compiled by Idaho National Laboratory are for *total* losses. The data already include the loss of primary and secondary sources of offsite power at plant sites. No data had been collected on *partial* LOOP events which might prove useful to licensees in their plant-specific analyses. Rather, several licensees used the total LOOP data in effect as partial LOOP data, then credited plant-specific features such as an emergency reserve auxiliary transformer to effectively reduce the probability of sequences leading to core damage. In the absence of reliable data for partial LOOP events, the licensees' methods were not appropriate. Licensees agreed to revise their LOOP analyses after the staff expressed these concerns.

Loss-of-service-water frequency. As discussed above, the SPAR models use a value based an operating experience for the total loss of service/raw water (LOSW) frequency. The value is an estimate based on the number of applicable reactor-years in the United States with no observed, sustained total loss during power operation. Aware of the wide variability of site characteristics and service water system design, the staff generally had minimal concerns about plant-specific frequencies that differed from the SPAR value. However, in several instances, the staff observed LOSW frequencies that were as much as two orders of magnitude below the SPAR value and most generally accepted values used in the industry PRA models. The staff was particularly concerned when the site in question had experienced precursors to LOSW events such as frazil ice, sea grass clogging of screens, debris infiltration, and other events. The staff requested the licensees to reconsider their initiator frequencies in light of operating experience, and most licensees agreed to increase the LOSW frequencies to varying degrees and as much as an order of magnitude in two cases.

Credit for reactor pressure vessel (RPV) injection following BWR containment overpressure. The staff observed a number of instances in which Birnbaum values for EDGs, residual heat removal pumps, and/or emergency service water (ESW) pumps in the licensees' PRAs were lower than expected. Closer review revealed that the amount of credit taken for RPV injection following BWR overpressure could have a significant impact on CDF and Birnbaum values. In two cases, sensitivity studies performed by the licensees indicated that this credit reduced the internal events CDF by factors of about 2 to 3. Additionally, Birnbaum values for important components such as EDGs and ESW pumps would increase by an order of magnitude without such credit.

The staff conducted extensive reviews for several plants where this credit appeared to be a factor in the PRA outlier status. Information useful to the staff in its reviews included:

- potential containment failure modes, pressures, and locations
- location of piping penetrations
- systems credited for injection
- location and environmental qualification of mitigating equipment
- reactor/auxiliary building room heatup calculations from steam ingress
- dependencies and location of equipment necessary to depressurize the reactor and keep the safety relief valves open
- location of backup nitrogen supplies
- time available for operator action
- containment event trees to address the phenomena
- sensitivity studies of the potential impact of various key assumptions.

The staff reviewed all relevant information in detail and found the information provided by the licensee to be acceptable for MSPI implementation. The staff plans a number of additional studies associated with these issues as part of RASP.

Station blackout mitigation after battery depletion. A number of licensees took significant credit for station blackout mitigation following station battery depletion. The staff's primary concern is with the ability to monitor critical process variables, control important equipment, and operate high-voltage circuit breakers in the absence of DC power. In several instances, the licensee informed the staff of the availability of batteries dedicated to switchyard operation. Additionally, licensees provided information on relevant procedures and training for the mitigation measures in question. The staff reviewed the information on an individual basis. Where the licensees provided sufficient bases for the credit, the staff accepted the modeling for the purpose of MSPI implementation. In one case, the licensee agreed to not credit operator recovery actions for certain sequences.

6.0 Generic Industry PRA Issues

The staff identified several PRA issues generic to the industry during the MSPI PRA outlier resolution process. The following describes three of the more significant examples.

Model truncation and convergence. The ASME PRA standard provides specific guidance and instruction regarding appropriate PRA model truncation levels and CDF convergence. During its reviews, the staff identified several concerns about the truncation levels in some of the preliminary PRA model quantifications performed by licensees. In several instances, the licensees did not demonstrate an adequate degree of convergence of the CDF in the PRA model. In other cases, while the analysis showed the CDF to be adequately converged, the licensees did not demonstrate adequate convergence of the Birnbaum values (derived from the CDF and Fussell-Vesely values). Sensitivity studies performed by the staff, as well as those published in the open literature, have identified that in many instances truncation levels need to be an order of magnitude or more lower for Birnbaum values to be converged to the same precision as CDF, especially for low Fussell-Vesely and Birnbaum values. In one instance, the licensee demonstrated by way of sensitivity study that reduction of the truncation level from 3×10^{-11} to 1×10^{-12} resulted in a 17 percent increase in CDF and a 30 percent increase in the Birnbaum value for the component in question.

As a result, the MSPI working group specified several options for the licensees to use in their PRA model quantification. The default option is to use a truncation level seven orders of magnitude lower than the baseline CDF. Thus, if the baseline CDF is, for example, 1×10^{-5}/yr, a truncation limit of 1×10^{-12}/yr would be acceptable. However, for a number of licensees, their PRA models were too large or the number of cut-sets generated too great to allow quantification in a reasonable amount of time. Therefore, the working group provided two alternative approaches. One alternative allowed for the derivation of Birnbaum importance measures for monitored components based on first principles, i.e., by requantification of the model with basic event probability set to 1.0 (failed). The second alternative approach allowed for use of higher truncation limits by demonstrating adequate convergence of the Birnbaum value for the monitored component(s) in question. The staff was satisfied that the licensees ultimately demonstrated adequate levels of truncation and convergence for MSPI implementation.

Small loss-of-coolant accident (LOCA) frequency. During the PRA outlier resolution process, the staff identified a systematic bias in the Birnbaum values for the high-pressure safety injection (HPSI) pumps in the SPAR models. Overlaying the plots of the distribution of Birnbaum values from the SPAR models and from industry PRAs for PWRs demonstrated that, on average, SPAR HPSI pump values were significantly lower than industry values. Review of the underlying data from industry and SPAR clearly showed that the industry's small LOCA-initiating event frequencies were significantly higher than the mean value of 4×10^{-4}/yr used in the SPAR models. For example, WCAP-16464-NP (Reference 2) provides the small LOCA initiator frequencies for Westinghouse/Combustion Engineering plants. The median initiator frequency for this group of plants is approximately 3×10^{-3}/yr, or nearly an order of magnitude higher than the SPAR value. The data also indicate a range of plant-specific frequencies spanning a factor of about 40 from a low of 2.5×10^{-4}/yr to a high of 1×10^{-2}/yr. While the definition of "small" LOCAs can vary from plant to plant, this variation would appear to exceed reasonable expectations. For example, plant-specific LOCA analyses may define "small-break" LOCAs to be between 1/2-inch and 2-inch equivalent diameter sizes at one plant, while another plant might have used 3/8-inch as the lower bound and 1.9-inch as the upper bound. Regardless, these small differences in the definition of break size can hardly account for the large variation in initiator frequencies.

While there generally is good consistency across the industry as to what constitutes medium-break and large-break LOCAs, such is not the case with small LOCAs. Some licensees include mechanical failure of reactor coolant pump seals in the small LOCA category, while others have split off the low end of the small LOCA spectrum and created small-small or very small LOCA categories, which have altogether different success criteria than small LOCAs. A consequence of this inconsistency in small LOCA definition and variation in small LOCA frequency is the difficulty of making direct comparisons between the SPAR models and the industry PRA models as a whole. The industry could significantly enhance PRA modeling by standardizing the process for defining LOCAs and for apportioning the total LOCA frequency in those cases where some plant-to-plant variation is necessary because of design differences.

PORV success criteria for bleed and feed. In a few cases, the PRA outlier resolution process identified major differences in the Birnbaum values for auxiliary feedwater (AFW) pumps that were attributable to variation in success criteria for pressurizer PORVs for bleed and feed. For example, a number of plants have used 2-of-2 PORVs in their success criteria, while other plants have specified 1-of-2. Still other plants have used a combination of 2-of-2 and 1-of-2 based on sequence specific circumstances. While there are design and procedural reasons for such variation (specifically, reactor thermal power rating and PORV relief capacity), often the success criterion is the result of the degree of analysis undertaken by the licensee. In one case, the staff reviewed nearly a thousand pages of analysis prepared, in part, to establish plant-specific success criteria. The staff's review of WCAP-16464-NP (Reference 1), which summarizes bleed-and-feed success criteria as well as PORV relief capacity, identified some lack of consistency within the industry in this regard.

For some plants with a high degree of redundancy and diversity of power supplies for AFW, for example, the calculated CDF and overall risk profile may not be sensitive to this criterion. For still other plants, it has been demonstrated that the CDF can vary by as much as a factor of 2 or 3 depending on this criterion. One objective of the SPAR Model Development Project is to account for plant-specific variation in design, and hence success criteria, for the use of such mitigation strategies as bleed and feed. However, it is not possible to duplicate the wide variation in success criteria while still maintaining the degree of standardization desired in the SPAR models, especially if the industry has different success criteria. As discussed above, the staff is initiating a study to perform confirmatory analyses in support of system success criteria that differ from the standard set in the SPAR models (e.g., the number of pressurizer PORVs needed for bleed-and-feed success in PWRs). This study is being performed as part of RASP.

7.0 Comparison of Licensee PRA Model CDF with SPAR Model CDF

The staff compared the April 1, 2006, licensee CDF values to the most current SPAR values. Although only about half of the SPAR models have undergone the latest phase of enhancement, 80 percent of the SPAR model CDFs are presently within a factor of 2 of licensees' internal events model CDFs. The average SPAR model CDF is approximately 8 percent higher than the average licensee CDF, so no significant systematic bias in the SPAR models is evident. The staff considers this a strong validation of SPAR model fidelity.

8.0 Summary of Results

Implementation of the MSPI represents a major step forward for risk-informed performance indicators. It is widely perceived as the first industrywide application using a structured process to address PRA quality.

Before MSPI implementation, the staff established a systematic process to understand PRA modeling differences. This process examined differences both within the industry, by comparing PRA values for classes of similar plants, and between plant PRA models and the NRC's own SPAR models.

The process identified PRA differences with the potential to impact the MSPI, then set out to identify whether those differences originated in bona fide design differences, differences in plant operating procedures and performance, or PRA modeling methods and assumptions. In the process, the staff screened in over 260 candidate PRA outliers, which eventually consolidated to several dozen plant-specific issues. The staff then addressed these issues in detail and resolved all PRA outliers before MSPI implementation on April 1, 2006. From these PRA reviews, the staff gained important insights into potential enhancements to both the NRC's

SPAR models and the industry PRA models. As part of RASP, the staff is now planning to address the most important remaining issues affecting SPAR model fidelity.

9.0 References

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