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# INITIAL EXPERIENCE WITH THE

# NRC SIGNIFICANCE DETERMINATION PROCESS

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### INTRODUCTION AND BACKGROUND

The U.S. Nuclear Regulatory Commission (NRC) has revamped its inspection, assessment, and enforcement programs for commercial nuclear power plants. The new oversight process uses more objective, timely, and safety-significant criteria in assessing performance, while seeking to more effectively and efficiently regulate the industry. The NRC tested the new process at thirteen reactors at nine sites across the country on a pilot basis in 1999 to identify what things worked well and what improvements were called for before beginning Initial Implementation at all US nuclear power plants on April 2, 2000. After a year of experience has been gained with the new oversight process at all US plants, the NRC anticipates making further improvements based on this wider experience.

The impetus behind this comprehensive change in approach came from both the NRC's own fundamental reviews of its regulatory program as part of the "reinventing government" process and from concerns expressed by the nuclear industry, Congressional committees, and public interest groups. The commercial nuclear power industry in the United States is a mature industry. Most of the more than 100 nuclear plants have been operating for more than 10 years, and half of them have operated for more than 20 years. All evidence suggested that the safety and reliability of the nuclear industry had improved markedly since the mid-1980's. The improvements in performance could be attributed both to efforts within the nuclear industry and to successful regulatory oversight. Despite this success, the NRC noted that processes for inspection, assessment, and enforcement were not always focused on the most important safety issues. In addition, some regulatory activities were considered redundant or inefficient and, at times, were seen as overly subjective. Also, NRC actions were not always sufficiently understandable or predictable.

To address these concerns, the new oversight process calls for: 1) focusing inspections on activities where the potential risks are greater; 2) applying greater regulatory attention to facilities with performance problems; 3) using objective measurements of performance whenever possible; 4) providing timely and understandable assessments of plant performance; 5) minimizing unnecessary regulatory burden; and 6) responding to violations of regulations in a predictable and consistent manner that reflects the safety impact of the violations.

The new program is, of course, anchored in the NRC's mission to ensure public health and safety. The objective is to monitor performance in three broad areas: reactor safety (avoiding accidents and reducing the consequences of the accidents if they occur); radiation safety for plant workers and the public during routine operations; and protection of the plant against sabotage or other security threats. Each of these "Strategic Performance Areas" are then subdivided into "cornerstones" (See Fig 1).

Performance indicators use objective data to monitor performance in each of these cornerstones and are measured against established thresholds which are related to their effect on safety. The results are color coded to facilitate assessment and communication activities. "Green" represents performance only calling for the NRC's baseline oversight (i.e., no significant deviation from expected performance). "White" signifies performance outside expected bounds, but, with very small effect on accident risk. This calls for increased regulatory response focused on the identified performance issues. "Yellow" signifies a reduction in safety margin and requires regulatory response focused on the causes of identified performance issues. "Red" identifies unacceptable performance and a significant reduction in safety margins.

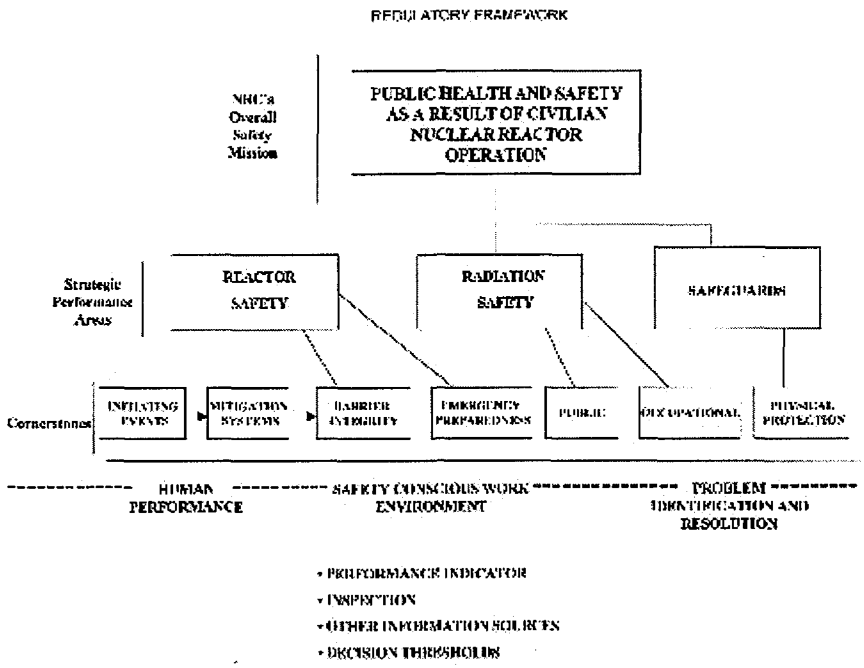


Figure 1

While performance indicators can provide insights into plant performance for selected areas, the NRC's inspection program provides a greater depth and breadth of information for consideration by NRC in assessing plant performance. The redesigned inspection program was developed using a "risk-informed" approach to select areas to inspect within each cornerstone based on their importance from the point of view of potential risk, past operational experience, and regulatory requirements. The degree to which the area is measured by a performance indicator also affects the scope of inspection activities. The inspection program has four major areas: 1) "baseline" - the minimum inspection at all facilities regardless of performance, 2) "supplemental" - additional inspection activities in response to performance identified issues, 3) event response, and 4) generic safety inspection. The baseline inspection program has three parts: 1) inspections of areas not covered or not fully covered by a performance indicator, 2) inspections to verify the accuracy of performance indicator data, and 3) a comprehensive review of the utility's effectiveness in finding and resolving problems.

Under the new oversight process, nuclear plant performance is measured by a combination of performance indicators and inspection program findings. The "Significance Determination Process" (SDP) provides a mechanism to characterize the safety significance of inspection findings and correlate this result to the performance indicators via color coding. The outcomes (both performance indicator and inspection findings) are then compared to the "Action Matrix" to determine NRC response. The Action Matrix provides for five levels of regulatory response to identified licensee performance: 1) all inputs "green" - normal baseline activities, 2) one or two inputs "white" in different cornerstones - increased regional inspection focused on followup to identified performance issues, 3) one degraded cornerstone (two inputs white or one "yellow") or three white inputs in a strategic performance area - additional regional inspection focused or cause of performance, 4) repetitive or multiple degraded cornerstones - increase agency level attention focused on causes of degraded utility performance, and 5) unacceptable performance - plant not permitted to operate.

Informal reviews of licensee performance are performed on a continuous basis as inspection findings and performance issues are identified. Each calendar quarter, the resident inspector and the regional inspection staff review the performance of all plants in that region as measured by the performance indicators and inspection findings. Every six months this review is expanded to include planning of inspections for the following six-month period. Each year, the final quarterly review involves a more detailed assessment of performance over the previous 12 months and preparation of a performance report. This annual review is also used to affirm that those plants with declining performance have been appropriately considered. These plants will be discussed at an annual meeting of the NRC's senior managers and during a public Commission meeting on plant and oversight program performance. Following the Commission meeting, the annual performance reports for all plants will be issued and the NRC staff will hold public meetings with each licensee to discuss the previous year's performance. This annual report will be made available on the NRC's public website. In addition, all performance indicator data and inspection finding information, along with any pertinent reports, are available on the NRC's public website and are updated quarterly.

## THE SIGNIFICANCE DETERMINATION PROCESS

The NRC developed the "Significance Determination Process" (SDP), to aid NRC inspectors and staff in determining the safety significance of inspection findings and correlating the results to performance indicator outcomes by using color coding for the purposes of assessment and determination of agency response via the "Action Matrix." In fact, the SDP is a collection of processes focused in the areas of reactor safety at power, containment, emergency preparedness, occupational radiation safety, public radiation safety, physical protection, fire protection, and operator re-qualification. The objectives of all these processes are: 1) to characterize the significance of an inspection finding for the NRC licensee performance assessment process, using risk insights as appropriate, 2) to provide all stakeholders an objective and common framework for communicating the potential safety significance of inspection findings, and 3) to provide a basis for assessment and enforcement actions associated with an inspection finding.

The SDP is applicable to all inspection findings with the exception of violations associated with willfulness, failure to report required information or inaccurate information. These issues are treated with the traditional enforcement process (severity levels) In addition, programmatic issues which have not resulted in a finding which can be treated with the current SDPs, are designated as "no color" findings and are treated under the traditional enforcement process. Licensee-identified issues, when reviewed by NRC inspectors, are also candidates for this process. The use of the SDP will be made regardless of whether the result or consequence constitutes a violation of a licensee's licensing or design basis or any other regulatory requirement or commitment. Agency follow-up of such issues, if determined to be significant, will be handled in accordance with the backfit rules of 10 CFR 50.109 as appropriate.

Inspection findings are observations (facts - details noted during an inspection) that have been placed in context and initially determined to be of sufficient potential significance to warrant more detailed review via the SDP. To determine if a finding is of sufficient potential significance, a finding must pass through the "threshold screening process." This screening process consists of three groups of questions. Group 1 questions are intended to parallel the Enforcement Manual's guidance on what constitutes a minor violation. Numerous examples are provided in this guidance for a variety of issues and provide clarity regarding complex issues such as those associated with Maintenance Rule findings. Group 2 questions are intended to determine if the identified issue impacts a cornerstone. Only issues which pass the Group 1 and 2 questions are appropriate for SDP analysis. Group 3 questions are designed to determine if extenuating circumstances exist that would warrant documentation of issues which do not pass the Group 1 or 2 questions.

### Reactor Safety - Initiating Events, Mitigation Systems, Barriers

This SDP provides a simplified risk-informed framework to estimate the increase in core damage frequency (CDF) during at-power operations due to conditions which contribute unintended risk increases caused by deficient licensee performance. Conditions which do not represent deficient licensee performance, as determined by the NRC staff, are considered part of the acceptable plant normal operating risk, and are not candidates for SDP evaluation.

The risk significance of actual reactor events caused or complicated by equipment malfunction or operator error are assessed by NRC risk analysts in accordance with applicable NRC event response guidance and not by the SDP. Although the SDP may provide useful insights, it was not designed or intended to be used for this purpose. The risk significance of an event is characterized by the probability that the core could have been damaged at the moment of the event given all known conditions. Conversely, the SDP estimates the increase in core damage frequency for the spectrum of all postulated initiating events over a period of time during which the known equipment or functional degradation existed.

The reactor safety SDP uses a phased approach. Phase one - characterization and initial screening - uses generic worksheets to fully and factually describe the known observations associated with the issue. Hypothetical conditions are not included, however, a bounding determination of significance may be made by assuming a worst-case condition (e.g., assuming complete loss of function, even if unsupported by the facts known at that time). If a bounding determination results in greater than green, greater factual detail will be necessary to complete the SDP. The Phase one worksheets also provide decision logic to determine if the issue can be characterized as green without the need for more detailed analysis of potential risk increase by Phase two. If the outcome of Phase one is green, no further action is required.

Phase two - initial risk significance approximation and basis - uses site-specific worksheets to define the applicable initiating event scenarios and estimate the likelihood of each scenario's initiating event. The worksheets are then used to estimate the remaining mitigation capability, including credit for operator action to recover. It should be noted that only equipment out of service for performance issues is considered out of service for purposes of this exercise. Equipment out of service for routine maintenance is already accounted for in the baseline core damage frequency for each plant.

Each applicable scenario's remaining capability rating is considered and evaluated against a color table. The most significant result is the outcome of Phase two. However, if three or more scenarios have borderline results (e.g., green adjacent to white), the higher significance will be considered during Phase three. This provides for consideration of the cumulative effect of the identified condition on all accident scenarios. If the outcome of Phase two is green, no further action is required.

During the initial review of site specific Phase two worksheets, NRC identified a weakness associated with external initiating events related to fire, flooding, severe weather, seismic, or other initiating events that are considered for licensees' IPEEE analysis. To compensate for this weakness, all Phase two results are screened for external event concerns.

If the Phase two result is green, but any of the following core damage sequence types result in a borderline outcome, the finding is screened for its potential risk contribution to Large Early Release Fraction (LERF) using the Containment Integrity SDP: ISLOCA, Transients, or Small LOCAs for all reactor containment types, ATWS for BWR Mark I reactor containment types, or SGTRs for all PWRs.

Phase three - risk significance finalization and justification - uses expert knowledge (e.g., senior risk analysts (SRA), equipment specialists, etc.) and program specialists to develop an NRC consensus, including the originating inspectors, of the significance of the inspection findings.

**Containment Integrity SDP**

Only a subset of core damage accidents that can lead to large unmitigated releases from containment in a time frame prior to effective evacuation of the close-in population have the potential to cause prompt fatalities. Such accidents generally include unscrubbed releases associated with early containment failure at or shortly after vessel breach, containment bypass events, and loss of containment isolation. The frequency of all accidents of this type is called LERF. Using this metric generally results in risk characterizations one order of magnitude more stringent than the CDF based approach.

The current approach being used is designed to closely interface with the CDF based SDP. If the finding is found to influence the likelihood of accidents leading to core damage, the the risk significance of the finding is determined using the CDF approach. If the finding does not influence LERF (as noted above), then the risk category is not increased and the SDP is complete. If the finding does influence LERF, a multiplication factor is determined, based on the accident scenario of concern, to approximate the impact of LERF considerations.

It is possible for a finding to be unrelated to those structures systems and components (SSCs) that are needed to prevent accidents from leading to core damage, but, to have potentially important implications for the integrity of the containment. The significance of findings of this nature are determined using a table provided based on the duration of the degraded condition.

**Shutdown Operations SDP**
This tool uses checklists to verify that the licensee is maintaining a shutdown mitigation capability (equipment, instrument, policies, procedures, and training) consistent with the NRC's estimate of industry shutdown risk presented to the Commission in the proposed Shutdown Rule (SECY 97-168). The check lists were developed for different plant operational states defined by: mode, time to boiling, reactor coolant system level, and reactor coolant system configuration. Each checklist is grouped by the five shutdown safety functions identified by NUMARC 91-06: decay heat removal, inventory control, power availability, reactivity control, and containment. As a plant enters into one of the plant operational states defined above, the inspector checks to ensure that each item on the checklist is being met. If an item is not met, the inspector compares the issue with the list titled "Findings Requiring Phase 2 Analysis" to determine if the finding should be forwarded to a region-based SRA to be quantitatively assessed. Findings not requiring quantitative assessment are screened green.

**Emergency Preparedness SDP**
This SDP consists of flow chart logic to disposition inspection findings. Emergency Preparedness (EP) regulations codify a set of emergency planning standards and requirements. The more risk significant areas of EP align with a subset of the planning standards and requirements. The SDP logic uses failure to meet or implement risk significant planning standards, planning standards, and other regulatory requirements as criteria for decisions. Failure to meet or implement the more risk significant planning standards results in greater significance.

**Occupational Radiation Safety SDP**
The objective of this cornerstone is to ensure worker health and safety from exposure to radiation from licensed or unlicensed radioactive materials during routine operations of civilian nuclear reactors. The health and safety of workers is assured by maintaining their doses within the limits in regulations and "as low as reasonably achievable (ALARA). This SDP consists of flow chart logic to disposition inspections findings in two areas: ALARA and exposure control.

ALARA findings are assessed by the actual job dose, the number of occurrences in the last 18 months, and the plants average collective dose to determine significance. Exposure control findings are assessed by the actual dose received versus regulatory requirements, the potential ("substantial") for an overexposure, and the effect on the licensee's ability to assess dose to determine significance.

### Public Radiation Safety SDP
This SDP consists of flow chart logic focused in four areas: radioactive effluent release, radioactive environmental monitoring, radioactive material control, and transportation. The logic is used to assess the finding regarding the dose/radiation involved versus the applicable regulatory limits and the ability of the licensee to control materials and assess dose and impact.

### Physical Protection SDP
This SDP consists of flow chart logic to determine the significance of inspection findings. Findings are assessed regarding access control or systems or safeguards plan vulnerabilities; whether an intrusion or malevolent act was involved; whether repeat deficiencies are involved (evaluated exercises); and whether a loss of function of one or more SSCs of a target set is involved.

Initially, this SDP was directly linked to the Reactor Safety SDP for more significant findings. While feasability reviews performed in the pilot program indicated the acceptability of this arrangement, during initial implementation this approach resulted in overly conservative determinations for evaluated exercise findings. Consequently, this connection was discontinued. Findings which involve a loss of one or more SSCs of a target set are reviewed (and must be approved) by senior NRC management for consideration of a significance determination greater than white.

### Fire Protection SDP
This SDP consists of three phases and is closely associated with the reactor safety SDP. Phase 1 is a screening method to eliminate (screen to green) findings that are unrelated to fire protection systems and features used to protect safe shutdown capability. Phase 2 analysis evaluates the synergistic impact of all related findings on risk by treating them collectively for a given fire area. Because of the integration of the reactor safety SDP with the phase 2 analysis, this analysis is generally performed by NRC fire protection engineers with technical assistance from regional SRAs.

### Operator Re-Qualification SDP
This SDP uses flow chart logic to determine inspection finding significance. The SDP first considers issues related to the licensee's grading of the exam to ensure that failed candidates or crews are properly identified and not passed inappropriately. The risk importance is not that the licensee's grading process was inadequate or flawed, but that inadequately trained operators may be allowed to go on shift.

The next parts of the SDP are related to the written and walkthrough portions of re-qualification and address issues of exam quality and security and the performance of multiple individuals. The risk determination assumes that a single individual failure does not rise to the risk significance of a green finding, however, when multiple failures are considered, more than 20% has been selected as the threshold for an unacceptable number of failures. This is consistent with the guidance in the examination standards.

The simulator portion of the SDP evaluates scenario quality and security and the performance of crews. Again, an individual failure does not rise to the significance of a green finding. The risk significance of crew performance depends on the percentage of crews that have failed, whether they were remediated before returning to shift, and whether the facility had a failure rate of green or greater in the previous annual operating test.

The failure rate risk significance can be determined by using the "Simulator Operational Evaluation Matrix" which compares the number of failed crews to the number of crews taking the test. The chart includes multiple units in order to accommodate those instances where operators hold dual licenses. If a multiple unit site has separate unit licenses, the matrix should be used to assess the results at each of the units separately.

Finally, the SDP looks at the overall re-qualification program by asking if less than 75% of the operators passed all portions of the exam and if more than 20% of the operator licensing records have operationally risk important deficiencies.

**Final Significance Determination**
When an inspection finding has the potential to be evaluated as more significant than green, the cognizant region schedules a meeting called SDP/enforcement panel (SERP) to discuss and reach agreement on the safety significance of the finding, the apparent violations and the requirements that should be cited, whether the case involves willfulness, and whether a Regulatory Conference or a pre-decisional enforcement conference should be conducted.

Throughout the process, it is expected that findings will be discussed with the licensee to ensure accuracy and completeness of facts under consideration. If the initial characterization is an "apparent significant finding," then the licensee is given the choice of formally presenting any further information or perspectives either in writing or during a public Regulatory Conference. This additional information, if any, will be considered prior to the final determination. It must be noted that minor computational disparities will not affect the final determination of inspection finding significance. If a licensee disagrees with the final determination, they may appeal the determination to the appropriate NRC Regional Administrator. Any such appeals must be based on either 1) actual (verifiable) plant hardware, procedures, or equipment configurations not being considered by NRC or 2) the NRC's determination was inconsistent with applicable guidance or lacked justification.

**EXPERIENCE WITH THE SIGNIFICANCE DETERMINATION PROCESS**
During the development of each SDP, a feasability review was performed to verify the efficacy of the process prior to implementation. For example, a feasability review for the reactor safety SDP is documented in SECY-99-007A, "Recommendations for Reactor Oversight Process Improvements (Follow-up to SECY 99-007)," dated March 22, 1999. This review looked at inspection findings at four operating reactors: D.C. Cook Units 1 and 2 for the period 1996 - 1997, Millstone Units 2 and 3 for the period 1994 - 1995, St. Lucie Units 1 and 2 for the period 1997 - 1998, and Waterford Unit 3 for the period 1997 - 1998. A second feasability study for the reactor safety SDP was performed in conjunction with the feasability review for the Event Response procedure and is documented in SECY-00-49, "Results of the Revised Reactor Oversight Process Pilot Program," dated February 24, 2000. This review looked at three specific events and the inspection findings associated with these events: Hatch Unit 2's June 15, 1999 loss of condenser vacuum, Beaver Valley Unit 2's July 17, 1999 electrical transient, and Indian Point Unit 2's August 31, 1999 scram with loss of off-site power. The conclusions of both studies supported the efficacy of the reactor safety SDP.

During the Pilot Program, few significant issues were identified. Therefore, the SDP was not fully exercised or field-tested. Consequently, during Initial Implementation, the SDP has received additional management attention and oversight. Significant modifications have resulted from lessons learned during Initial Implementation. Examples include the changes to the Physical Protection SDP discussed above and the addition of the Operator Re-qualification SDP.

The following are examples of inspection findings characterized by the various SDPs during Initial Implementation:

**Kewanee Auxiliary Feedwater Design Issue**
The licensee's UFSAR states that a trip (low suction pressure) is provided for each auxiliary feedwater (AFW) pump to protect it in the event that the Condensate Storage Tank (CST) supply to the pumps is lost following an earthquake or tornado. The pumps can be restarted following a manual switchover to take suction from the Service Water System (SWS). On July 13, 2000, during a design inspection at the Kewaunee Plant, NRC inspectors determined that the licensee could not verify the capability of SWS to provide an adequate source of water to the AFW system. The inspector's specific concern related to the potential plugging of the AFW suction

strainers due to the size of AFW pump suction strainers. A review of appropriate drawings verified the strainers were required but the drawings did not specify the mesh size of the strainer screens. Licensee personnel could not locate records or other documentation that specified the hole size or the material used for the strainers. Because of inspector concerns, licensee personnel opened and inspected the "A" AFW pump suction strainer on August 21, 2000. The installed strainer was approximately 10-inches long and had 1/16-inch diameter holes, much smaller than anticipated.

The AFW pumps are normally aligned to the non-safety related Condensate Storage Tanks (CST). Upon a loss of the CST supply, the AFW pumps are re-aligned to the safety-related SW system supply (Lake Michigan). The rotating strainers on the discharge of the service water pumps are designed to pass particulate material up to 1/8" in size. Therefore, it is possible to clog/plug the AFW pump suction strainers, rendering them inoperable. When this system condition was identified, the licensee determined that the plant was in an unanalyzed condition and declared all three AFW pumps inoperable. This condition appeared to have existed for approximately 25 years.

The NRC staff evaluated the risk significance of the inspection finding in terms of the contribution from both internal and external initiating events. Consistent with the guidance for the SDP, the change in core damage frequency (?CDF) was evaluated stemming from the identified plant design deficiency. External initiating events, earthquake, fire, and tornado/high wind were individually evaluated. The following summarizes the staff's finding based on the set of information available for the staff during the initial evaluation.

(1) <u>Internal Initiating Events</u>
The dominant sequence in this category is a transient followed by a complete loss of secondary cooling due to unavailability of the main steam and feedwater systems, failure of all CSTs, failure to switch over from the CSTs to SWS, and failure to establish bleed and feed. Given an internal initiating event, the failure probability of the CSTs is very small. The licensee's risk calculation indicated that the increase in CDF due to internal events was much less than $1\times10^{-6}$ per year. In addition, no sand and debris in the lake would be stirred up and introduced to the strainers as with an earthquake. In some cases, recovery of secondary cooling would also be available. The staff found the risk impact of the inspection finding due to internal initiating events to be negligible.

(2) <u>External Initiating Events</u>
a. *Earthquake* - The staff found this category to be the dominant contributor to the overall risk significance of the inspection finding. The postulated scenario is associated with an earthquake followed by loss of secondary cooling and failure to establish bleed and feed. The staff's assumptions and justifications are provided below:

- An earthquake occurs with a frequency of $1\times10^{-4}$ per year based on the Los Alamos National Laboratory (LLNL) Seismic Hazard Curve for Kewaunee.

- Offsite power is lost with probability one. This is consistent with the licensee's assumption in the IPEEE.

- The CSTs are damaged and lost with probability one. This is consistent with the licensee's assumption in the IPEEE.

- Instrument Air is lost with probability one. This is consistent with the licensee's assumption in the IPEEE.

- Operator fails to establish bleed and feed with probability 0.1. Given the plant conditions associated with the event, the staff considered the operator action to establish bleed and feed to be a high-stress operator action.

Based on these assumptions, the ?CDF was approximated to be $1x10^{-5}$ per year.

b. *Fire* - The licensee's fire risk analysis does not credit the alternate AFW water source from SWS given the loss of the CSTs. Therefore, the inspection finding would not have any risk implications due to fire. The staff found that even if modeled, the risk impact would be negligible due to the reasons similar to those for internal initiating events.

c. *Tornado and High Winds* - The licensee's IPEEE stated that the probability of a tornado striking a point in close vicinity of the site was calculated to be about $5x10^{-4}$ per year.

Conclusion

The staff's risk evaluation found the increase in CDF due to an earthquake to be about $1x10^{-5}$ per year. Due to the nature of the scenarios involved, the uncertainty of the risk significance can be high. The staff concluded the risk significance of the inspection finding based on the change in CDF to be WHITE.

**Indian Point 2 Steam generator Tube Leak**

On February 15, 200, Indian Point Unit 2 experienced a steam Generator tube failure. The event had moderate risk significance. It involved a steam generator tube failure that resulted in an initial primary-to-secondary leak of reactor coolant of approximately 146 gallons per minute, and required an "Alert" declaration (the second level of emergency action in the NRC required emergency response plan). The event resulted in a minor radiological release to the environment that was well within regulatory limits. No radioactivity was measured off-site above normal background levels and, consequently, the event did not impact the public health and safety. The licensee's staff acted to protect the health and safety of the public. Additionally, the necessary event mitigation systems worked properly.

Notwithstanding the above, the NRC identified problems in several areas including operator performance, procedure quality, equipment performance, technical support, and emergency response. These problems challenged the operators, complicated the event response, and delayed the plant cooldown. The NRC concluded that during the 1997 steam generator inspection, Con Edison did not recognize and take corrective actions for significant conditions adverse to quality relating to eddy current data collection and analysis and specific steam generator conditions. These missed opportunities caused significant limitations and uncertainties, resulting in tubes with detectable flaws being left in service. Collectively, these opportunities, along with a new active degradation mechanism, increased the likelihood of tube integrity problems during the subsequent operating cycle.

This performance issue was evaluated via the Reactor Safety SDP and the Containment Integrity SDP. Initial conclusions elevated the issue to a Phase 3 review by regional and headquarters experts. While the analysis of the risk factors associated with the inspection finding were detailed and numerically based, the conclusion did not rely solely on the results of the calculations. This complies with the intent of the reactor oversight process to be "risk-informed" rather than "risk-based."

Initial NRC Assessment:

During the February 15, 2000, event, the leakage did not reach the full steam generator tube rupture (SGTR) flowrate, due to remaining crack ligaments in the flaw area. However, if additional stress had been placed on the flaw by any larger than normal differential pressure the SGTR leakrate could have been reached. Therefore the risk analysis was done assuming a SGTR. The risk associated with the condition of the tubes comes from several potential accident sequences:

1. Spontaneous rupture of a tube, not successfully mitigated by plant operators, causing core damage and bypass of the containment by large radioactive releases.

2. Rupture of one or more tubes induced by a steam system depressurization event, not successfully mitigated by plant operators, causing core damage and bypass of the containment by large radioactive releases.

3. Rupture of one or more tubes induced by a reactor system over-pressurization event, causing core damage and bypass of the containment by large radioactive releases.

4 A core damage event that occurs with the reactor system at normal operating pressure, inducing tube rupture by increasing tube temperature and/or tube differential pressure, causing bypass of the containment by large radioactive releases.

Of these, the first two increase both the core damage frequency (CDF) and the frequency of large radioactive releases bypassing the containment and reaching the environment (hereafter assumed to be a "large early release"). The latter two sequences are already included in the plant's core damage frequency estimate, but would not normally be included in its large early release frequency (LERF). The induced tube ruptures cause them to make contributions to LERF.

The NRC staff estimated the sum of these tube degradation related risk contributions to get a yearly incremental CDF/LERF for an SGTR of approximately 1E-4/reactor year (RY). Using the single SGTR over a 23 month period established a low bound event frequency of approximately 0.5 SGTR/RY . Because the condition deteriorated with time, it can be argued that the initiating event frequency had not increased over the first year but only during the last year of operation. This would establish a high bound of 1 SGTR/RY. Multiplying these two estimates of the initiating event frequency by the SGTR CDF/LERF probability results in estimates for the incremental CDF of between 5E-5/RY and 1E-4/RY.

The following table was used as guidance.

| Table 1 Risk Significance Based on LERF and CDF | | |
|---|---|---|
| **incremental CDF Range/RY** | **SDP Based on CDF** | **SDP Based on LERF** |
| $\geq 10^{-4}$ | Red | Red |
| $< 10^{-4} - 10^{-5}$ | Yellow | Red |
| $<10^{-5} - 10^{-6}$ | White | Yellow |
| $<10^{-6} - 10^{-7}$ | Green | White |
| $<10^{-7}$ | Green | Green |

Therefore, the CDF/LERF increment associated for a SGTR event was considered to be clearly above the $10^{-5}$/RY criterion for a RED significance determination.

<u>Con Edison Assessment:</u>
The preliminary Con Edison assessment stated that the probability of CDF resulting from a SGTR is 1E-6/RY the initially assumed frequency of a SGTR as 1.3E-2/RY, so the yearly incremental CDF conditional core damage probability is 0.77E-4/RY (1E-6/1.3E-2)

Con Edison completed a more detailed calculation of CDF for the actual conditions present at the time of the tube failure and for the actual leakrate observed. This calculation assumed that the flow rate from the leak remains at below the design basis rate, which reduces the time to core damage and postpones the release time to the point that Con Edison believed it would not be considered an early release.

Subsequently, the licensee was given the opportunity to present additional information at a Regulatory Conference held on September 26, 2000. The licensee's new analysis made several changes to the earlier assessments. The steam generator failure initiating event was split into two parts, according to break flow rates, a Monte Carlo analysis was performed to estimate the frequency of the two break sizes, human error probabilities were reduced for events with the smaller break size, and 87% of the resulting core damage frequency (CDF) was removed from the LERF category on the basis of considerations regarding the path the radioactive materials would travel from the damaged core to the atmosphere. The licensee's analysis did not address the potential for additional LERF due to tube failure during a core damage accident that might be caused by some event unrelated to tube condition, such as a station blackout. The licensee's final result was a CDF contribution of 6.6 x $10^{-6}$/ry and a LERF contribution of 3.6 x $10^{-6}$/ry. If accepted by the staff, this would have changed the significance level to YELLOW on the basis of the LERF contribution.

Final Significance Determination:
The NRC staff reviewed and analyzed the information provided by the licensee and concluded that, when all contributions to LERF were considered, the condition being assessed was most appropriately categorized as "red," with its LERF increment above the 1 x $10^{-5}$ threshold. This was true even when considerable credit was given for reduced human error probabilities for the smaller break size events and the licensee's rational was credited for taking much of the spontaneous rupture CDF contribution out of the LERF category. Although the range of the sensitivity study results did cross the "red/yellow" numerical threshold, the staff did not consider that to be an appropriate basis for a "yellow" finding for several reasons. Foremost is the fact that the LERF reduction effect that was the subject of the sensitivity case had not been credited in any previous staff risk assessment and had not been studied by the staff to verify the magnitude of the effect. In addition, when that effect was credited, the larger portion of the range of the results remained on the "red" side of the numerical threshold.

It is the nature of risk analyses that numerical results are very uncertain. Although not expected, it is possible that knowledge gained in the future would alter this analysis sufficiently to change the conclusion regarding the "color" determination for a similar future inspection finding. However, for the purpose of assigning a color to past licensee performance, the NRC staff believed that the performance should be judged on the basis of the risk perceptions at the time of the performance associated with the inspection finding.

**Salem Unit 2 Fire Protection Issue**
During the baseline triennial fire protection inspection, the NRC identified the failure of the 4160Vac switchgear room carbon dioxide fire suppression system to achieve the minimum fifty percent concentration when it was originally installed and tested. Additionally, the licensee identified that the system did not contain a sufficient supply of $CO_2$ for two full discharges into the largest protected area as required by design.

The significance of these findings was evaluated with the following considerations:

! All three divisions of 4160 Vac Switchgear are located in the 4160Vac Switchgear room. The switchgear trains are separated from each other by radiant energy shield walls.
! The safe shutdown cables in the room overhead are protected in such a manner that one train is protected by an electrical raceway fire barrier system. The raceway fire barrier system is required to have a 1 hour fire rating. Testing by the licensee demonstrates that the actual rating varies and in some cases is as low as 10 minutes, resulting in a medium to high degradation of the fire barriers.
! The room is protected by a smoke detection system and a manually actuated $CO_2$ suppression system. A medium degradation was assigned for automatic protection.
! A fire brigade drill was witnessed and the brigade performance was found to be satisfactory corresponding to a low degradation for manual suppression.
! Due to the room configuration and the routing of essential cables, credit was given for the recovery of one train within the fire area.

The NRC analysis concluded that the risk associated with these issues amounted to a WHITE determination. The licensee agreed with this characterization.

**Indian Point Unit 2 Emergency Preparedness Issue**
In response to the February 15, 2000, event involving a steam generator tube failure, the NRC initiated an Augmented Inspection Team (AIT) to promptly establish the facts associated with the event. This inspection found that an untimely augmentation by the emergency response organization (ERO) had occurred in that required staff were not in-place within the required time (60 minutes from declaration of the Alert) as required by the facility's Emergency Plan. Specifically, the following staffing problems were noted:

- The technical support center (TSC) was supporting the event response 90 minutes from the Alert declaration and was not fully staffed until 2 hours and 51 minutes after the Alert declaration due to the inability to staff the following positions: core physics engineer, electrical and mechanical engineers.
- The operations support center (OSC) was not fully staffed until 1 hr and 46 minutes after the Alert declaration due to the inability to staff the Health Physics positions.
- The emergency operations facility (EOF) was not fully staffed until 1 hour and 46 minutes after the Alert declaration due to the inability to staff the onsite and offsite monitoring teams.
- The emergency news center (JNC) was not staffed until about 2.5 hours after the Alert declaration. No activation or staffing requirements were listed in the Media Relations Emergency Plan for the facility.

Followup inspection identified a number of program structure or design deficiencies indicating an apparent failure to meet NRC planning standards. These deficiencies were: ERO notification process and equipment reliability problems, ERO delays in onsite access by the security force due to procedure and training problems, and some delays due to personnel not knowing where to report once onsite. The risk associated with these findings was characterized by the NRC as WHITE.

**Callaway ALARA findings**
During a routine baseline inspection, NRC inspectors found that, because of poor planning, as well as other causes, six jobs that accrued more than 5 person-rems each during the previous refueling outage exceeded their projected dose by more than 50 percent. The NRC preliminarily determined that the violation was composed of three parts. Of the six jobs in question, two accrued actual doses greater than 25 person-rems. Thus, because the licensee's 3-year rolling average, collective dose exceeded 135 person-rems (but did not exceed 340 person-rems), each was considered a WHITE finding. In addition, since there were more than two other jobs that accrued more than 5 person-rems (but less than 25 person-rems), these constituted an additional WHITE finding, for a total of three WHITE findings.

**OVERALL CONCLUSION**
Overall, feedback from inspection staff, NRC management, and licensee personnel has been positive and supports the conclusion that the SDP has provided a means to: 1) characterize the significance of an inspection finding for the NRC licensee performance assessment process, using risk insights as appropriate, 2) provide all stakeholders an objective and common framework for communicating the potential safety significance of inspection findings, and 3) provide a basis for assessment and enforcement actions associated with an inspection finding. These objectives will continue to be monitored and assessed as part of the reactor oversight self-assessment program.