Template NRR-105

March 16, 2000

MEMORANDUM TO: Thomas L. King, Director
Division of Risk Analysis and Applications
Office of Nuclear Regulatory Research

FROM: Mark Cunningham, Chief
Probabilistic Risk Analysis Branch
Division of Risk Analysis and Applications
Office of Nuclear Regulatory Research

SUBJECT: TRIP REPORT FOR SITE VISIT TO GRAND GULF NUCLEAR STATION

On July 7, 1999, Sandia and Brookhaven National Laboratories' staff visited Grand Gulf Nuclear Station (GGNS). The purpose of the visit was to collect information on methods and tools employed by the licensee to evaluate and manage low power and shutdown (LPSD) risk.

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Trip Report for Site Visit to Grand Gulf

On July 7, 1999, a site visit was conducted at the Grand Gulf Nuclear Station (GGNS) to obtain information about low power and shutdown (LPSD) activities at Grand Gulf. Attendees included:

- Gary W. Smith (GGNS),
- Mike Hindman (GGNS),
- John G. Booth (GGNS),
- Mike Withrow (GGNS),
- Deepak Rao (GGNS),
- Jerry Burford (GGNS),
- Charles A. (Drew) Bottemiller (GGNS),
- Tsong-Lun Chu (Brookhaven National Laboratory),
- Tim Wheeler, (Sandia National Laboratories [SNL]), and
- Donnie Whitehead (SNL).

The meeting opened with introductions and a brief discussion of the purpose of the meeting. The GGNS personnel then discussed how LPSD risk is managed and controlled at GGNS. As part of the discussion, SNL and BNL personnel asked questions to help clarify and/or confirm the information presented by GGNS. This information is summarized in Attachment 1 (Completed LPSD Questionnaire from Site Visit: Grand Gulf). In addition, GGNS provided the following five handouts with LPSD related information:

Attachment 2 – Grand Gulf slide presentation package,
Attachment 3 – Risk profile plots,
Attachment 4 – NS&RA Report OA-98-02, RF09 Post Outage Assessment,
Attachment 5 – NS&RA Report OA-98-01, Safety Assessment of the RF09 Outage Schedule, and
Attachment 6 – Grand Gulf Nuclear Station Shutdown Operations Protection Plan, Rev. 2.

The meeting was adjourned on June 7 at approximately 3:00 pm.

Attachment 1

Completed LPSD Questionnaire from Site Visit: Grand Gulf

1. **How is LPSD risk controlled or managed at your facility?**

   Key elements include:
   - Independent key safety functions reviewed,
   - ORAM assessment,
   - Shutdown and cooling independent assessment,
   - Independent safety engineering oversight,
   - Protected train/equipment,
   - Industry events insights, and
   - Shutdown operations protection plan.

- **What resources are allocated to controlling LPSD risk?**

   - Design Engineering
   - Outage Scheduling
   - Nuclear Safety & Regulatory Affairs (NS&RA)
   - Others as specific activities and risk evaluations dictate

Scope and Level of Detail Questions

1. **What is the scope of your LPSD analyses (e.g., transients, loss of coolant, fire, flood, seismic, planned outages, unplanned outages, plant operating state transitions, others)?**

   - Evaluates Transients/LOCAs/Fire (Protected trains)
   - Planned outages only (ORAM)
   - Unplanned outages evaluated using the SOPP methodology

   The scope of the GGNS LPSD analyses includes accidents and transients, and planned outages. Unplanned (i.e., forced) outages are typically not analyzed because the activities are generally narrowly focused and of short duration. GGNS has modified ORAM to enable it to identify the risk-significance of shutdown cooling train/system-swap over; other operational state transitions are not normally included in the scope. The risk significance of external events (fire, internal and external flooding, and seismic events) are typically covered qualitatively by administrative controls and guidelines in place at GGNS. This includes the use of the "protected train" concept, which ensures that a train of qualified/protected equipment is available during floods and seismic events. In addition, it should be noted that GGNS is a low seismic plant which limits the risk impact of an earthquake.

2. **What are the bases for your current decisions to include or exclude:**
   - **initiating events (e.g., loss of decay heat removal, loss of support system, fire, and flood),**

     External events (including internal fires and floods) are not included to keep the model manageable.

Protected train approach used for external events like fires and floods.

- **operational states,**

  Generally included (Modes 4 and 5)

- **outage types (i.e., planned, unplanned, forced, unforced, etc.)**

  Included with different emphasis - e.g. use of SOPP for forced outage scenarios

- **fuel pool cooling, fuel handling, and/or fuel misloading, and**

  Considered to be having a negligible impact on public health risk.

  They are evaluated independently. Risk is minimized within reason. Off-site dose well within regulatory limits.

  Misloading events analyzed by reload team and essentially screened out because of administrative controls and doubled checking.

- **transitions between operational states.**

  Minimal modeling of DHR alignment.

  Transitions by NS&RA.

3. **Are there any scope issues that you believe should be included that are not now included in your analyses?**

   SFP heat load and risk.
   See Question 6, in the LPSD Risk Analysis Results Questions.

4. **What additional research or guidance (if any) would be required before these issues could be efficiently addressed?**

   Improved modeling techniques/methods for transitions between operational states would provide a more complete (i.e., better) understanding of the risk posed by this activity.

5. **What is the level of detail used in your analyses? Is it the same as or different from the level of detail used in your full power analyses?**

   Train level with initiating events and dependencies; uses prequantified results for train failure rates and unavailabilities.

SSCs are taken out of service at the train level; we generally do not model at the component level.

6. **How did (or how do) you decide what level of detail is appropriate?**

   We consider this level of detail to be appropriate for quantifying the refueling outage risks and capturing impact of typical scheduling options.

   Overall, we believe that in general, LPSD risk is much lower than At-Power risk; therefore, we do not believe that much additional expenditures of effort in the LPSD risk modeling area is cost-beneficial.

7. **Are there any instances where you think the level of detail currently used might prove inadequate? If so, where?**

   Yes, in certain cases. These are evaluated based on outage specific activities - e.g. the RF06 and RF07 evaluations that we performed on evolutions relating to our recirc discharge gate valve repair with jet pump plugs in service.

8. **What guidance, if any, should be provided on the appropriate level of detail for an analysis?**

   We believe that specifying guidance regarding analysis detail is inappropriate. Some situations dictate a detailed analysis whereas others warrant far less detail.

9. **How does your LPSD risk assessment scope meet the guidelines of NUMARC 91-06?**

   No answer provided.

Methods and Assumptions Questions

1. **What are the basic methods and approaches (e.g., ORAM, EOOS, Safety Monitor, defense-in-depth, or probabilistic risk assessment) that are used to manage LPSD risk at you facility?**

   ORAM

   KSF (Key Safety Function) assessment

   Defense in Depth (SOPP)

   Selected additional risk analyses as appropriate (*e.g.*, the assessment of the recirc discharge gate valve repair discussed above)

2. How or why do you choose methods and approaches for use in a particular analysis?

Typically a multi-pronged approach like the one we use provides a better handle on the overall big picture for risk and for important plant evolutions and special situations, without the excessive burden posed by routine use of extremely detailed models.

We believe that no single method is appropriate for all situations, and engineering judgment, coupled with an awareness of potential vulnerabilities for each stage of the outage provides a good balance of safety and efficient use of resources.

3. What are the strengths and weaknesses (if any) of the methods and approaches that you use?

Strengths:

- GGNS total risk assessment utilizes analyzed risk, deterministic evaluations and considerations, and "tribal knowledge" on the conduct of safe outages
- Risk results from ORAM
- SOPP treatment of equipment unavailability
- Awareness of CSF (critical safety functions) and their status during various outage scenarios
- Independent assessment using NS&RA's KSF assessment

Weaknesses

- Data in ORAM model is not the most recent
- Train level modeling
- Conservative boiling calculations – do not take credit for realistic heat sinks. This conservatism might contribute to the masking of more important failures.
- Conservative treatment of recoveries and compensatory actions

4. If there are any weaknesses, can these weaknesses be minimized by additional research? If so, what additional research would you suggest?

- an easily usable thermal hydraulic computer code for better estimating boiloff while including a realistic treatment of heat sink impact would be useful

- additional research on the extension of surveillance intervals - this could maybe justify going to divisional refueling outages. What impact does changing the 18-month surveillance intervals have on estimates of equipment failure probability?

- AOT flexibility to permit more on-line maintenance

- LPSD CDF vs. At-Power CDF - are they comparable in impact? What is a good factor to apply to LPSD CDF to make it comparable in impact to At-Power CDF

Completed LPSD Questionnaire from Site Visit: Grand Gulf (Continued)

5. **What are the major assumptions (e.g., development of success criteria, human performance, and appropriate data sources) used in your analyses?**

   Per NSAC 175L

6. **What are the bases for these assumptions?**

   Per NSAC 175L

7. **What method(s) do you use to identify and quantify potential human errors?**

   Per NSAC 175L

8. **Do theses methods have any limitations that you would like to see corrected? If so, what are they?**

   We have not evaluated these methods or assumptions sufficiently to answer this question.

9. **For the data included in your analyses (e.g., initiating events, equipment failure rates, and maintenance unavailabilities) what are your sources and how do you analyze the information?**

   Failure and initiating event data is from NSAC 175L. Plant specific data includes outage specific decay heat load and core lattice calculations, and equipment unavailabilities.Human Reliability Analysis (HRA) methodology is essentially from NSAC 175L.

10. **As a result of your data analysis, are there any specific data needs that you have identified? If so, what are they?**

    None, however, some initiators and failure data is old. New data is not expected to significantly affect results, insights or decision making.

11. **Based on your current LPSD analyses, are there any areas that require additional research (e.g., boron dilution, maintenance or testing induced drain-down events, nuclear grade crane failures, impact of the definition of "Success Terms" on the selection of computational tools, fire and flood initiators, cold overpressurization, and impact of plant procedures (both emergency and administrative) on LPSD modeling assumptions)?**

    Additional research on Shutdown CDF and At-Power CDF would be useful. Guidance to compare the two, while considering the inherent conservatisms in the LPSD models (relating to the much higher time periods for recovery, and the decay heat profile as a function of time) would be useful for the nuclear industry so that these risks could be put in a better perspective and fairly compared.

Completed LPSD Questionnaire from Site Visit: Grand Gulf (Continued)

LPSD Risk Analysis Results Questions

1. **What are the results from your LPSD analyses?**

   The GGNS process includes:

   - Shutdown Safety Function Assessment Trees (SSFAT) - Deterministic evaluation of Tech Specs and Shutdown Operations Protection Plan (SOPP) requirements using defense in depth and other plant specific requirements.

   - Probabilistic Shutdown Safety Assessment (PSSA) - Risk analysis giving quantified values for CDF and boiling risk at each stage of the outage.

   - Nuclear Safety & Regulatory Affairs (NS&RA) evaluation of outage activities using ORAM and other tools to evaluate conditions. Report provides insights and suggested contingency actions and measures for each stage so that there is heightened awareness for higher risk outage evolutions.

   GGNS develops a baseline risk risk profile of the as-planned schedule before the outage as an evaluation tool. Configurations during the outage can be planned, modeled, and compared for relative risk impact. And, finally, a risk profile is developed of the as-performed outage activities as a post-outage study. The profiles include both a Core Damage Profile and a Boiling Risk Profile. Examples of these profiles are attached for the RF08 and RF09 outages.

   In the RF08 example, both the average Core Damage risk and the Boiling risk profiles were lower for the as-performed activities than for the as-planned schedule. In the RF09 example, the average Core Damage risk was higher for the as-performed activities compared to the as-planned schedule. The average Boiling risk, however, was less for the as-performed schedule.

2. **What core damage frequency and release metrics do you use?**

   - Core Damage Frequency (CDF) – both instantaneous and average,
   - Boiling Risk– both instantaneous and average,

3. **Why do you think these are the appropriate metrics to use?**

   These metrics are good surrogates of Large Early Release Frequency (LERF), and capture impact of changes in plant conditions and equipment availabilities.

   LERF is essentially zero for almost the entire refueling outage duration; if LERF is used, then comparisons between various outage evolutions are more difficult; Boiling Risk and CDF are considered good surrogates for LERF for refueling outage scenarios.

4. **If you do not currently use a release metric (e.g., large early release frequency), what is your bases for not doing so?**

   LERF is a very good metric for measuring public health risk and for comparison of LPSD risk to risk at Full Power operation.

   LERF is the appropriate metric to use in regulation of nuclear power plant activities, as it is the metric most relevant to public health risk [the regulators' mission is to ensure adequate protection of the public health and safety].

   See response to Question 3.

5. **What characteristics should a release metric possess to be useful in LPSD analyses?**

   Provide a measure of public health risk impact. Alternatively, an appropriate surrogate metric such as core damage or boiling risk could be effectively used for planning purposes.

6. **Are there other metrics that should be considered for LPSD analyses? If so, what are they?**

   - Fuel Pool Boiling Risk
   - Fuel Damage risk associated with SFP boiloff and draining

   are additional metrics that perhaps may be potentially useful in LPSD analysis and for optimizing outage planning.

   GGNS does not believe additional metrics are required. However, two areas of potential risk significance are fuel pool boiling and fuel damage risk associated with SFP draindown or boiloff. Generally, SFP component maintenance is typically performed online. Time to boil curves for the SFP are considered in the SOPP; thus these risks are currently handled qualitatively. At present, we believe that use of these additional quantitative metrics is not going to appreciably improve LPSD risk assessment.

Structure and Format of LPSD Standard Questions

1. **Is a LPSD Standard needed? Please explain your answer.**

   We believe that an LPSD Risk Standard is not needed.

   We believe that in general, LPSD risk is much lower than At-Power risk (current risk estimates are driven by the conservatisms and in the methods and analysis); therefore, we do not believe that much additional expenditures of effort in the LPSD risk modeling area is cost-beneficial

2. **If a LPSD Standard is needed:**
   - **what should be its scope and structure,**

     No applicable. See answer to question 1.

   - **what are the appropriate risk metrics, and**

     Not applicable. See answer to question 1.

   - **should it endorse any specific methods or techniques for analyzing LPSD risk?**

     Not applicable. See answer to question 1.

Attachment 2

GGNS

"To be the best operating BWR in this country"

Schedule Development

- Logic Based Schedule
- Critical Safety Function Focus
- Divisional Approach
- Operations Involvement
- Comprehensive Review

Logic Base

- Beyond simple Hammock Approach
- Nuclear Safety
- Operational Considerations
- Resource Utilization

Risk Management Process Overview

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■ Key Elements

- *Independent Key Safety Functions Review*
- *ORAM Assessment*
- *Shutdown Cooling Independent Assessment*
- *Independent Safety Engineering Oversight*
- *Protected Train / Equipment*
- *Industry Event Insights*
- *Shutdown Operations Protection Plan*

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Outage Nuclear Safety

- SOPP and Schedule Tie
- Numarc 91-06
  - Reactivity
  - Inventory
  - Decay Heat
  - Power
  - Containment

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Outage Nuclear Safety

- Divisional Approach
  - Protected Trains
- Senior SRO Involvement
- Operations Training

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"To be the best operating BWR in this country"

Outage Nuclear Safety

- Critical Safety Reviews

- ISEG Review
  - Qualitative
  - SOPP Validation
  - Expanded safety review (fire, heavy lifts, key evolutions)

- Shutdown Cooling Review
- Plant Safety Review Committee Approval

Shut/Down Operations Protection Plan(SOPP)

GGNS

"To be the best operating BWR in this country"

- Identifies shutdown risk management as a key in planning of outage activities
- Delineates outage management philosophy and guidelines
- Provides an organized approach for managing Key Safety Functions
- Maximizes "Defense in Depth" concept
- Serves as the focal point for the outage
- Integrates industry experience

Outage

GGNS

"To be the best operating BWR in this country"

- Key Safety Function Status Discussed at Turn-Over
- Independent Safety Engineering Provides Schedule Oversight
- Protected Train/Equipment Posted per SOPP
- Pre-Job Briefs on Industry Events as Appropriate

Outage Implementation

- SOPP Driven
- Emergent Work Risk Review
- Daily ORAM Schedule Validation
- Frequent communication of risk conditions

SOPP Conditions

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- Condition 1 - Reactor is in Mode 4
- Condition 2 - Reactor is in Mode 5 with Cavity level low or flooded with Gates installed.
- Condition 3 - Reactor is in Mode 5 with Cavity Flooded and Gates not installed
- Condition 4 - Reactor is defueled
  (Not planned for RF09)

Average Core Damage Comparison

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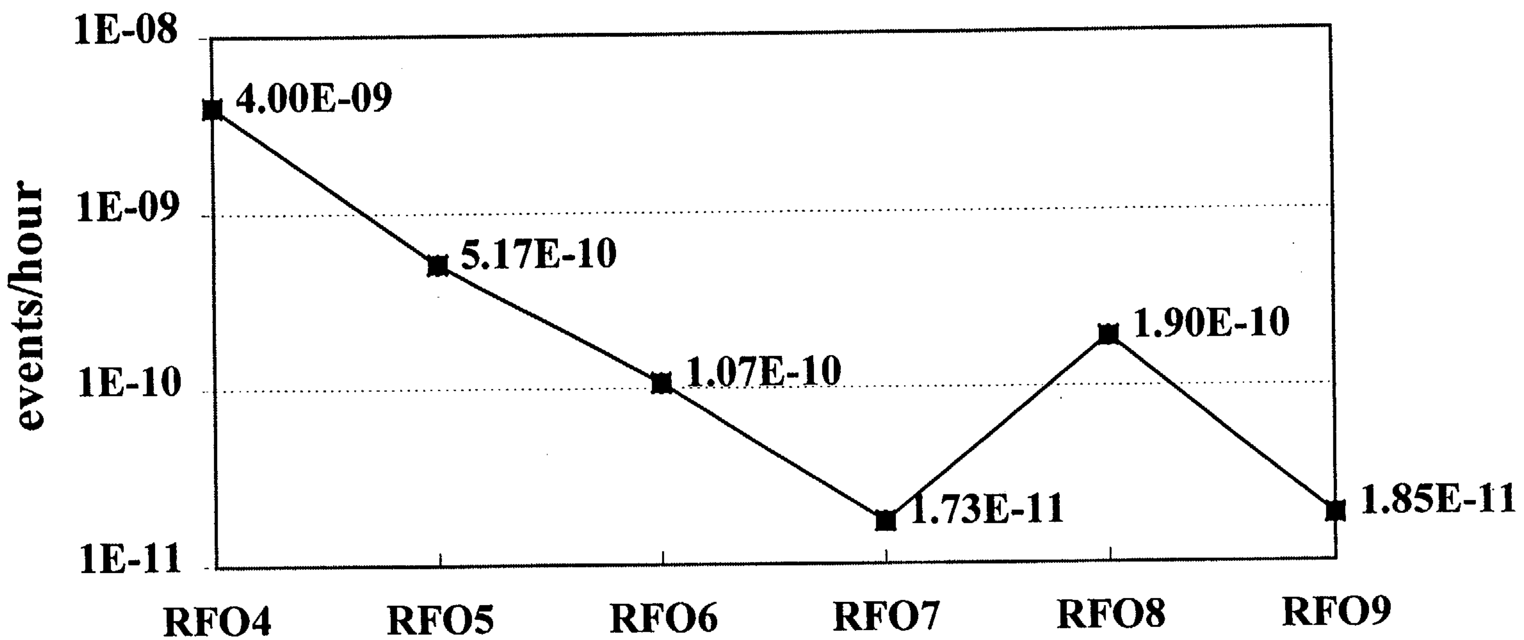
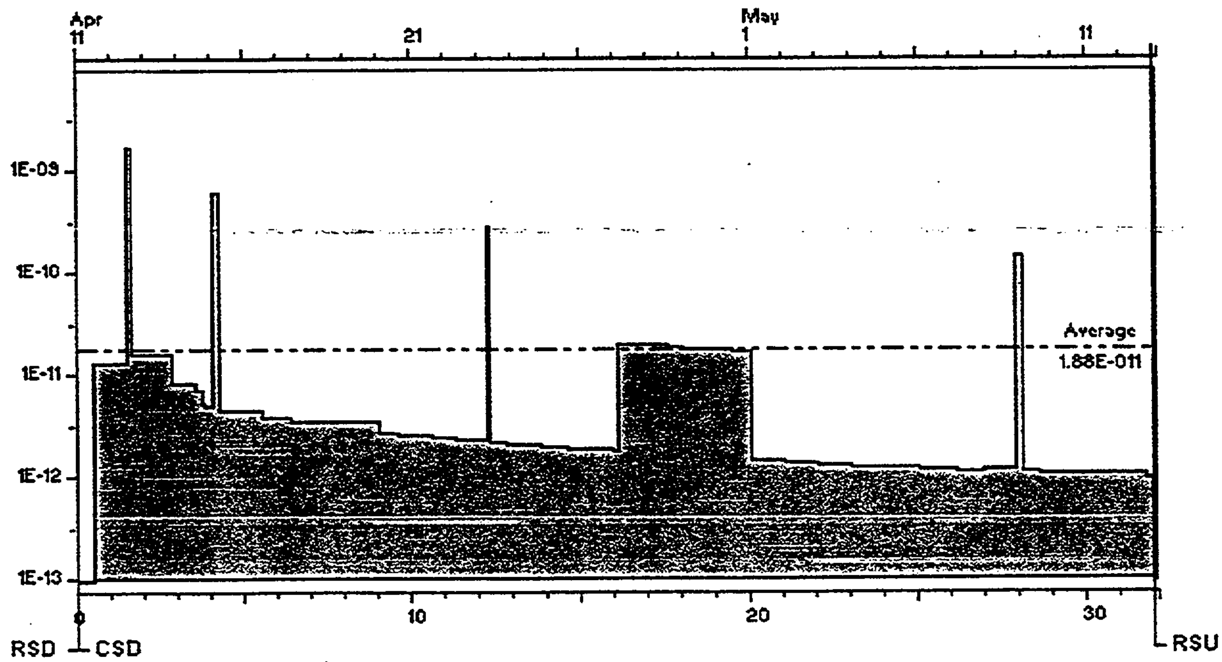
"To be the best operating BWR in this country"

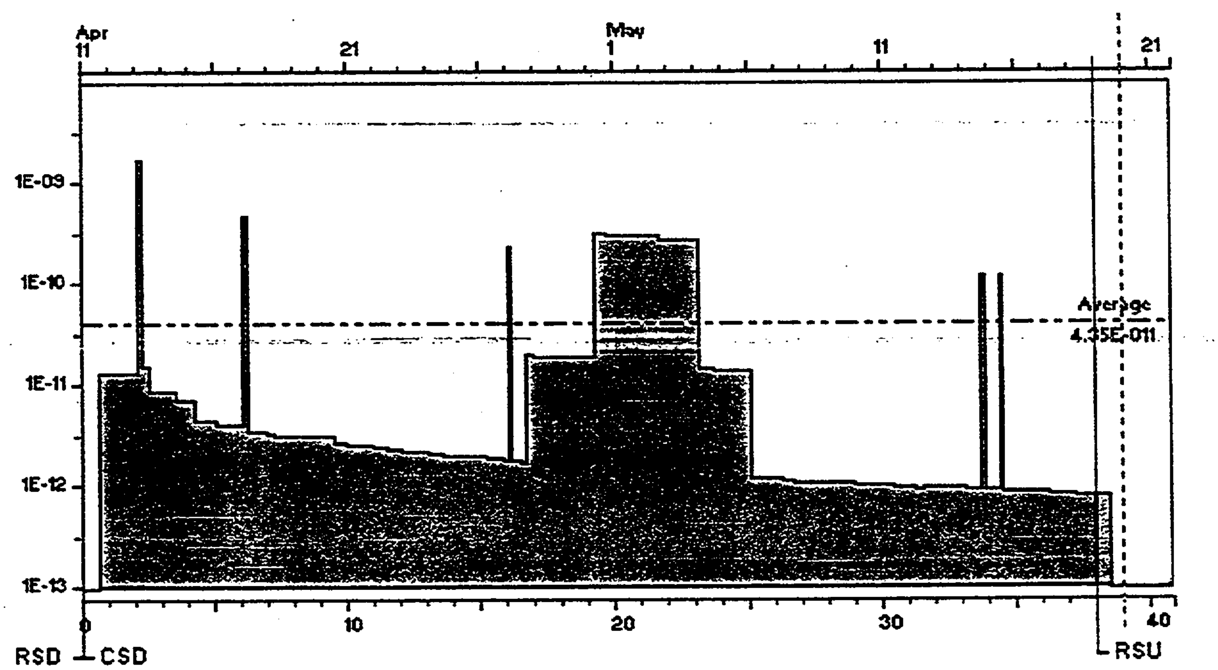


Attachment 3

RF09 Core Damage Risk Profile

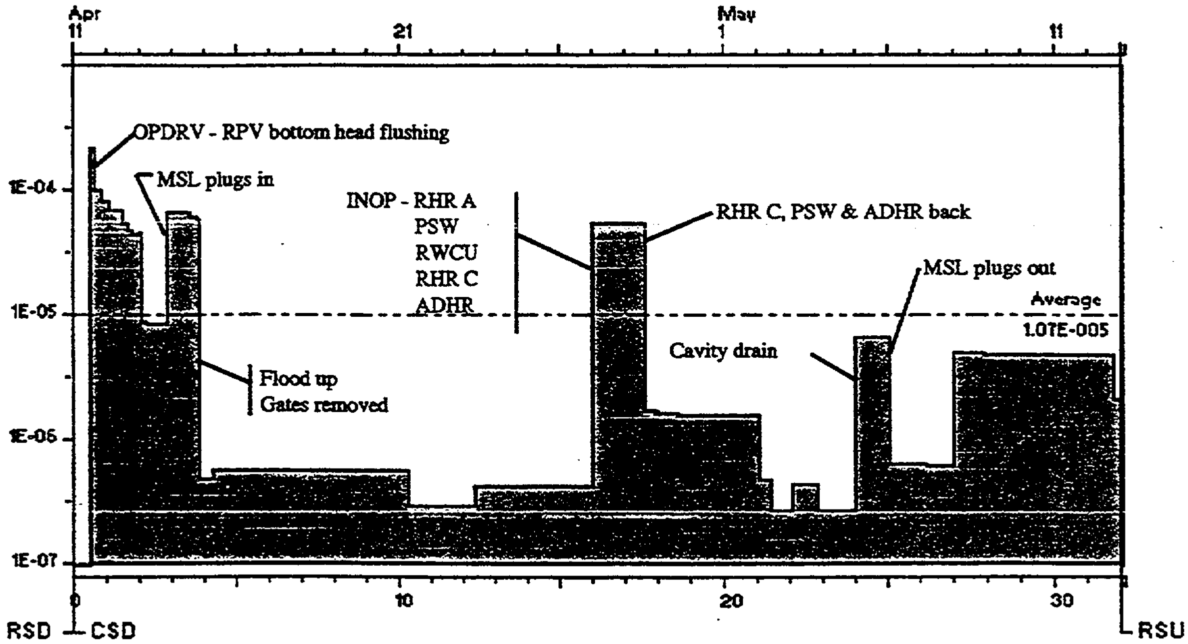


Baseline: April 20, 1998

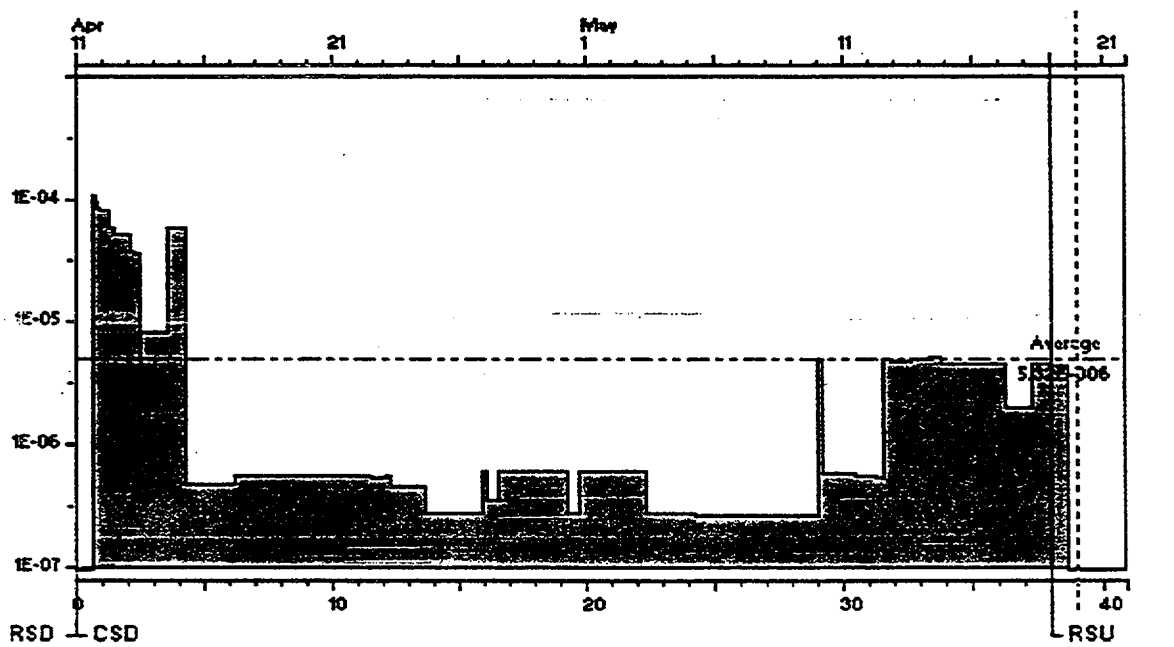


Outage Final Analysis: May 20, 1998

RF09 RCS Boiling Risk Profile

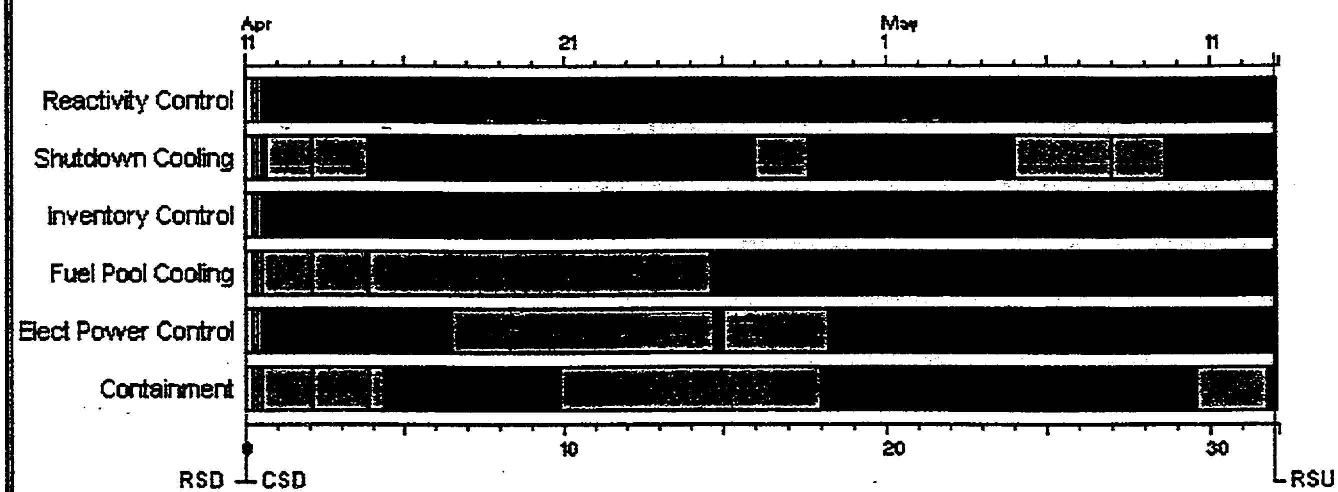


Baseline: April 20, 1998

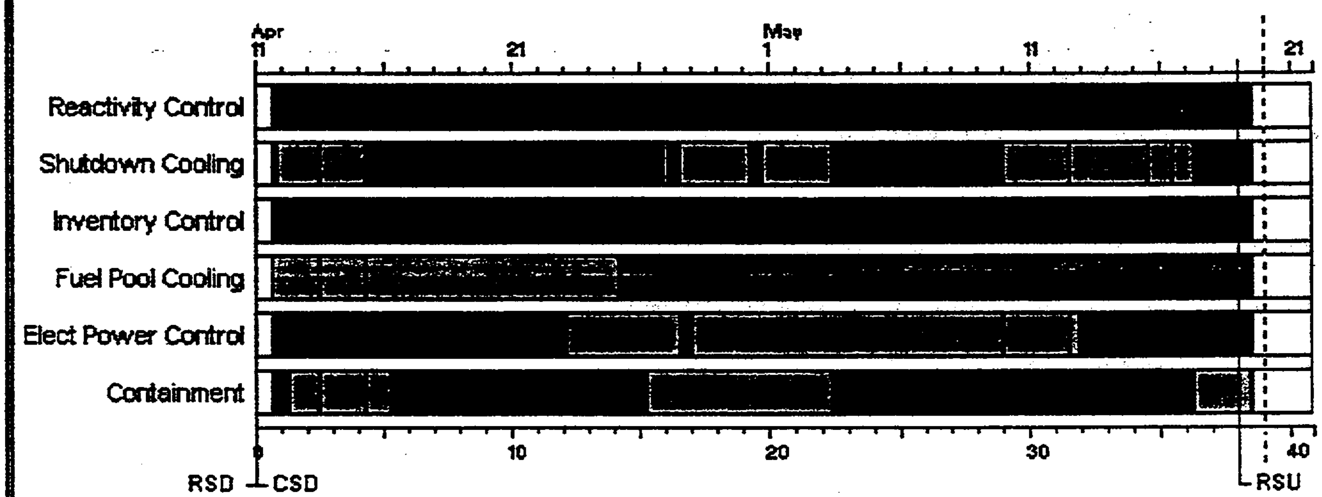


Outage Final Analysis: May 20, 1998

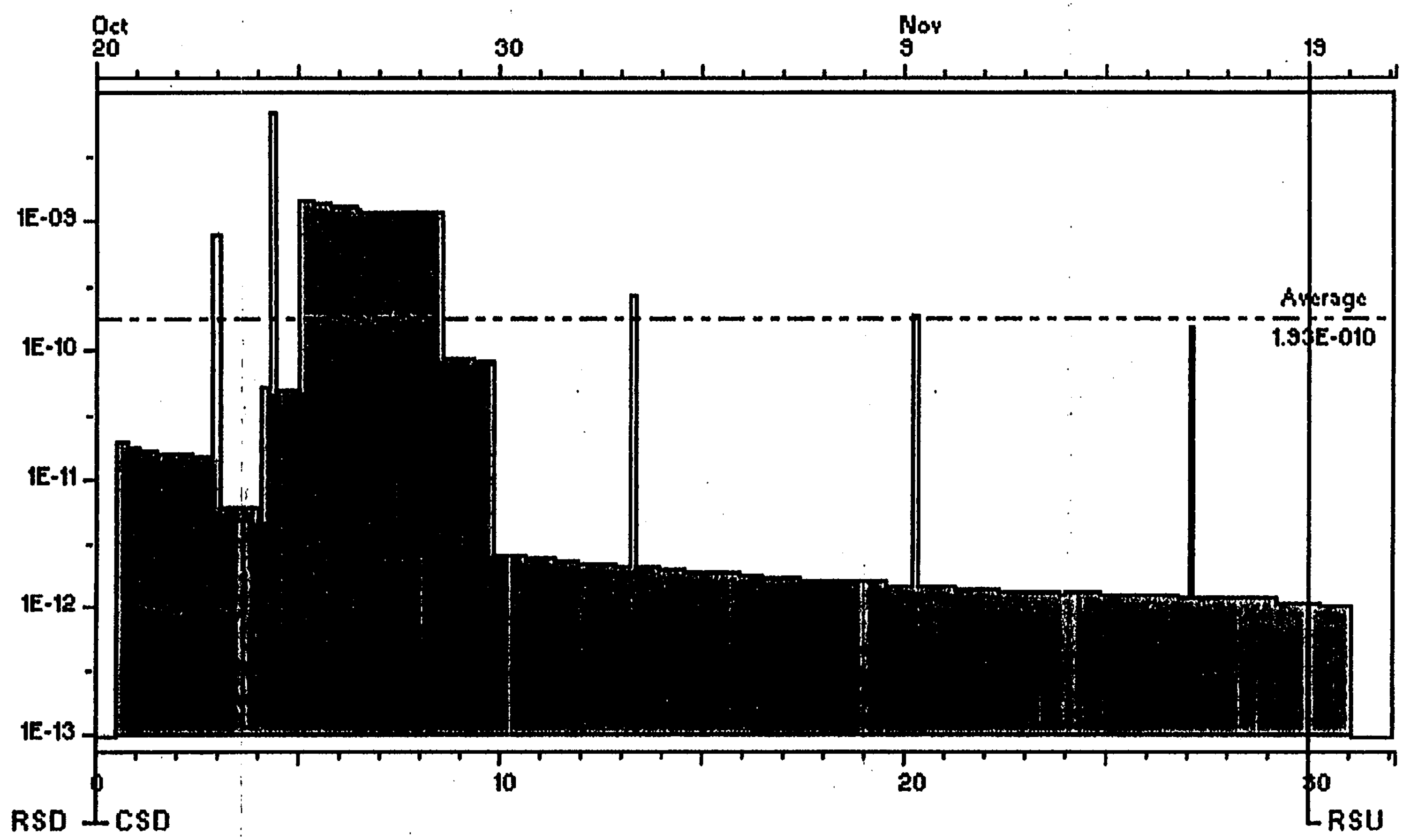
RF09 Key Safety Function Status



Baseline: April 20, 1998

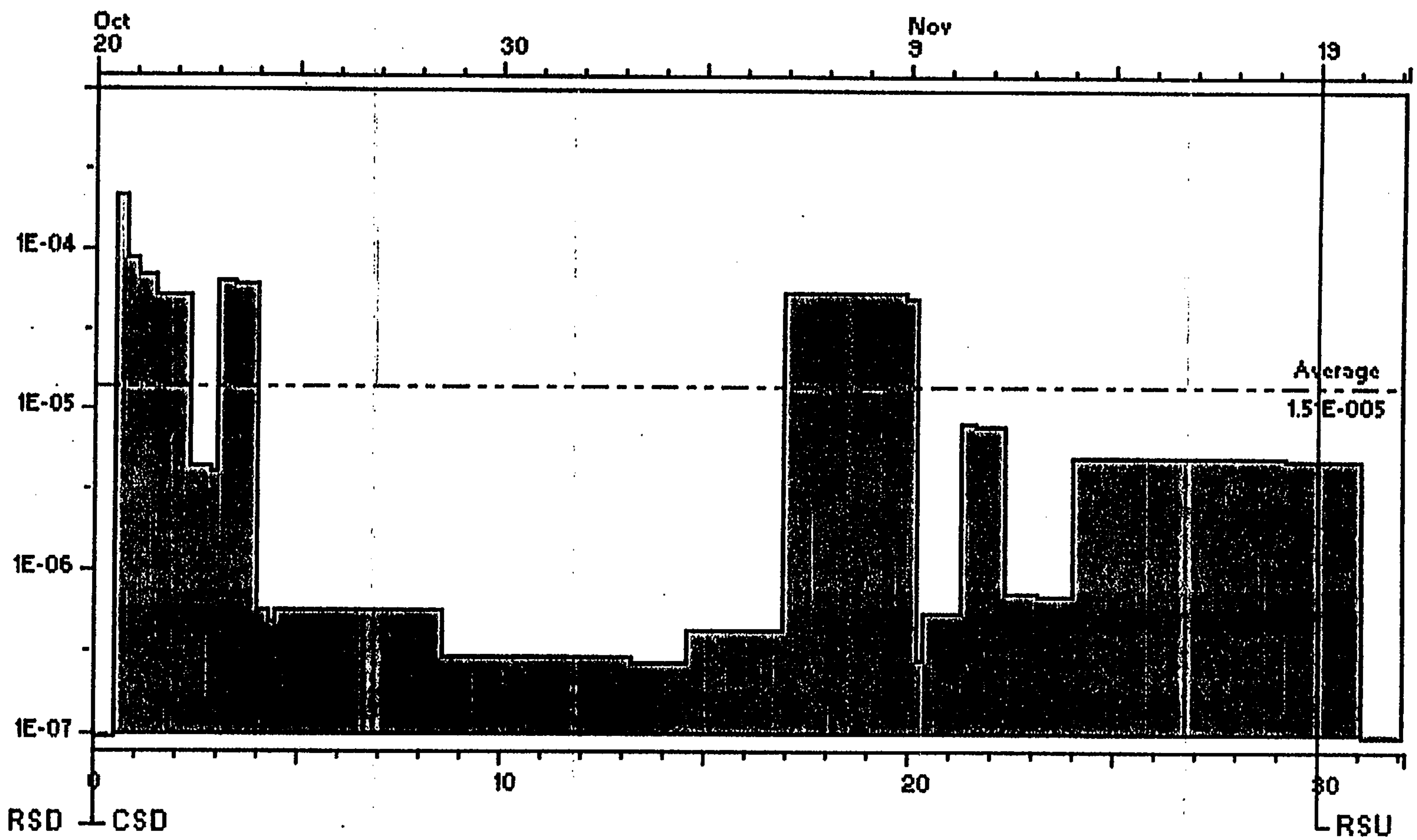


Outage Final Analysis: May 20, 1998



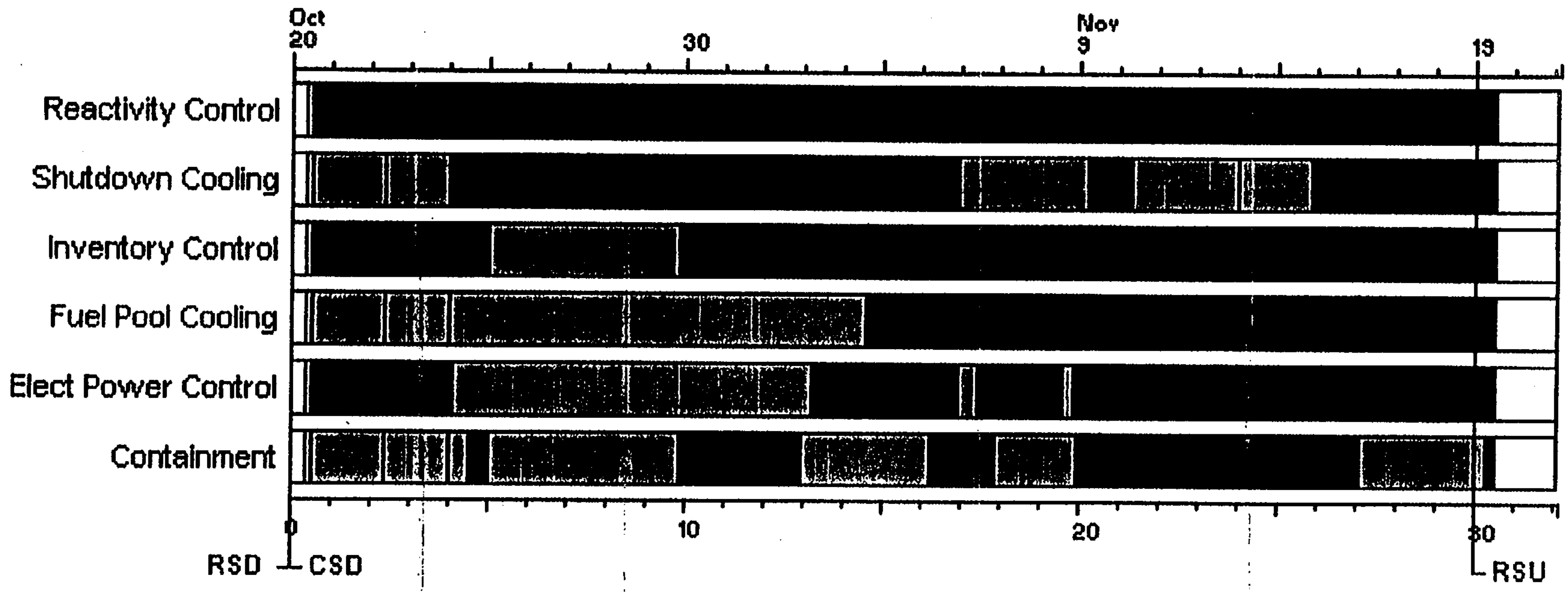
RF08 Core Damage Risk Profile

Baseline: October 16, 1996



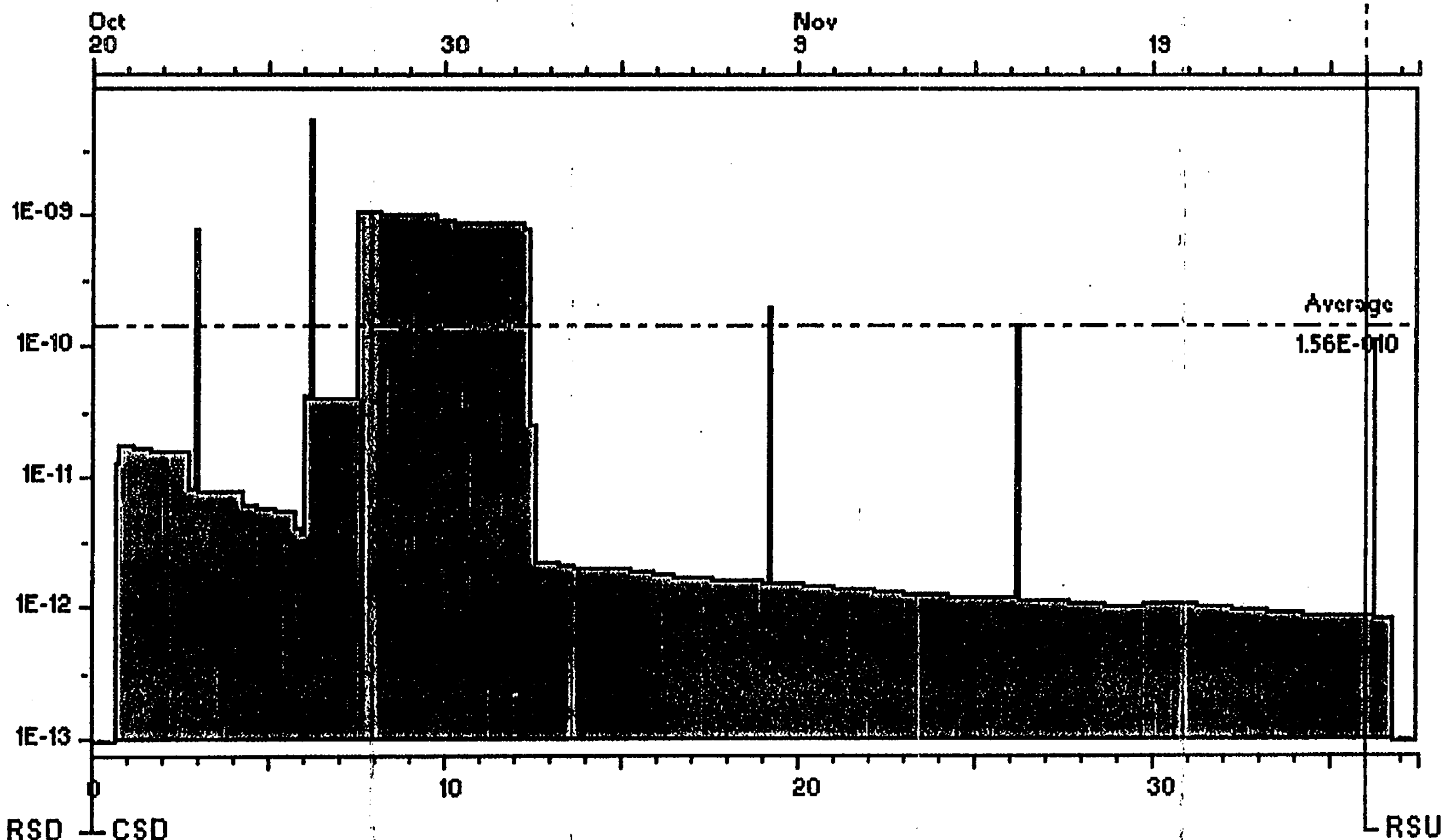
RF08 RCS Boiling Risk Profile

Baseline: October 16, 1996



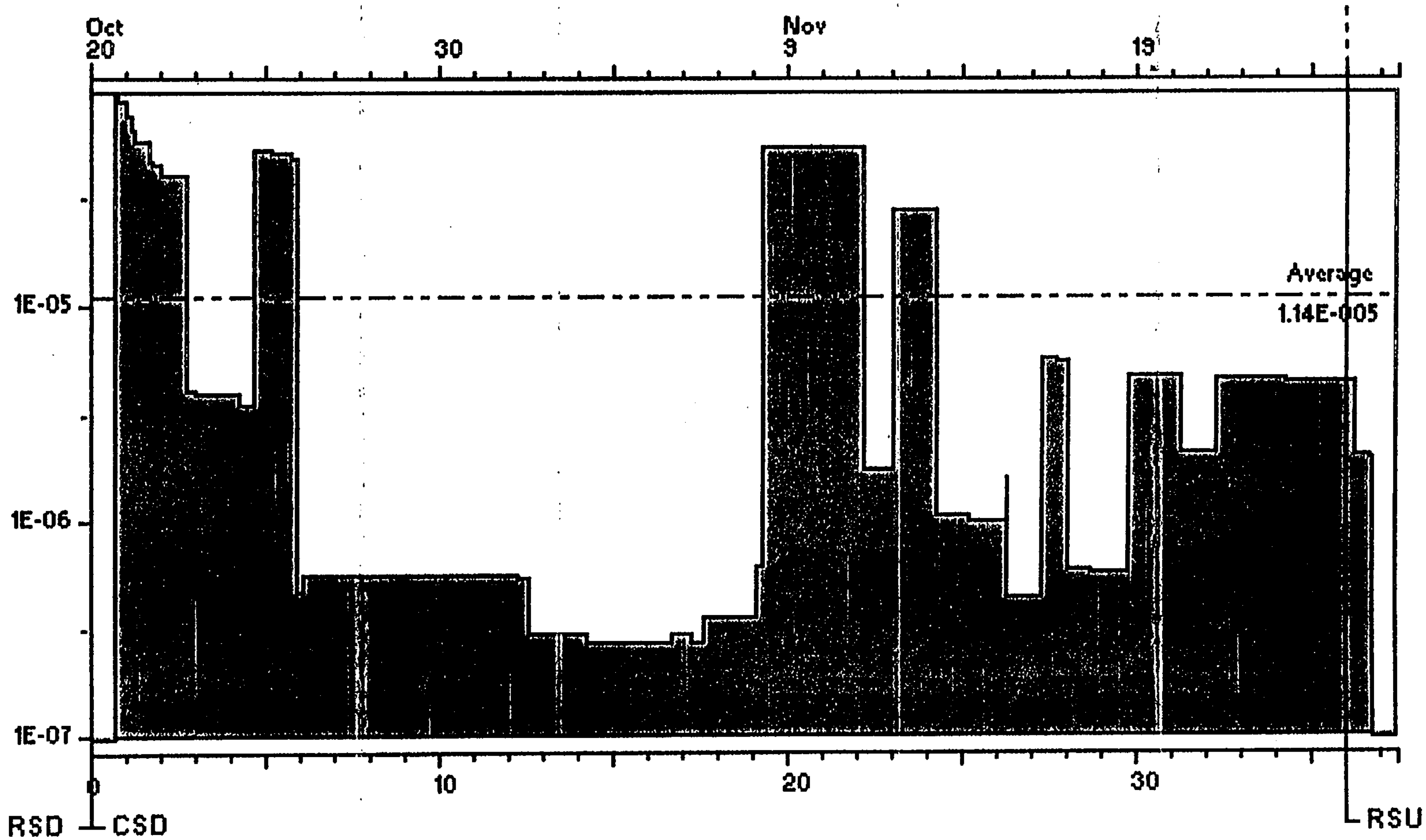
RF08 Key Safety Function Status

Baseline: October 16, 1996



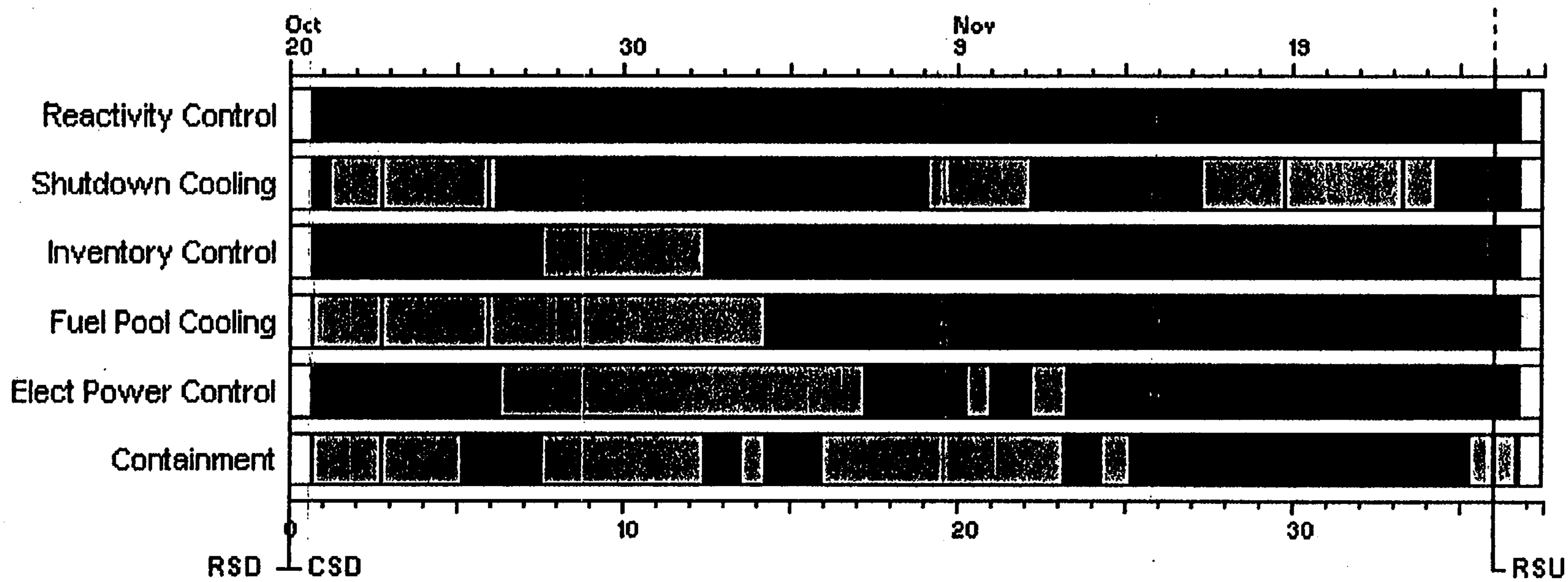
RF08 Day 37 Core Damage Risk Profile

Final: November 25, 1996



RF08 Day 37 RCS Boiling Risk Profile

Final: November 25, 1996



RF08 Day 37 Key Safety Function Status

Final: November 25, 1996

Attachment 4

Date: August 11, 1998

To: W. A. Eaton

From: L. F. Daughtery

Subject: NS&RA Report OA-98-02, RFO9 Post Outage Assessment

GIN: 98-01280

Attached for your review is the Safety Issues Group's RFO9 Post Outage Assessment.

GHL/ ghl

attachments: Report OA-98-02, RFO9 Post Outage Assessment

cc:

J. G. Booth w/a
C. E. Ellsaesser w/a
W. K. Hughey w/a
R. V. Moomaw w/a
J. C. Roberts w/a
C. D. Stafford w/a
M. J. Wright w/a
J. E. Venable w/a
File (NS&A) w/a
Central File, w/a [10]

NUCLEAR SAFETY & REGULATORY AFFAIRS
SAFETY ASSESSMENT SECTION

RFO9 POST OUTAGE ASSESSMENT

NS&RA REPORT NUMBER: OA-98-02

DATE: 8/11/98

Prepared: ______________________ 8/11/98
Cognizant Engineer/Specialist — Date

Approved: ______________________ 8/12/98
Safety Issues Supervisor — Date

SUMMARY

RFO9 was initially planned to be accomplished in 32 days. The outage was actually completed in 40 days, 18 hours, and 58 minutes. The most visible cause of the 8 day extension to RFO9 was the LP Turbine upgrade. However, other work items, such as the erosion/corrosion piping upgrade, would have had the same effect on the overall outage length. As the outage progressed some schedule changes were made because of problems encountered. These changes were analyzed by the Safety Issues Group and the results were reported to Outage Management. The changes did not cause a significant change in the overall outage core damage or boiling risk.

One of the major accomplishments during RFO9 was the installation of the ECCS suction strainer. This modification had the potential to significantly impact the availability of decay heat removal systems. However, due to excellent pre-planning and implementation, there was no impact on maintaining the availability of decay heat removal systems throughout the outage.

The overall planning of the outage from a risk perspective was thorough and well thought out, including changes to the schedule. The Outage Planning and Scheduling Group did an excellent job in this effort.

Recommendations by the Safety Issues Group were written as Outage Critique items and submitted to Outage Scheduling for incorporation into the RFO9 Outage Critique.

RESPONSIBILITIES:

The Safety Issues group performed a pre-outage schedule assessment to identify "risk conditions" in the outage so contingency plans could be developed subsequent to the start of RFO9. During the outage, the group assessed outage schedule changes and reviewed emergent plant maintenance items daily for impact on plant safety. The group additionally made periodic tours of the plant and main switchyard to verify the posting of "high impact" signs for protected equipment

WHAT WORKED WELL:

- Schedule changes - The changes to the RFO9 outage schedule were well planned by the Outage Scheduling Group. The Safety Issues Group monitored and assessed each schedule change for potential impacts on the overall outage risk. Even though the duration of RFO9 was extended by eight days, the outage schedule sequence was performed very close to the initial "as planned" schedule. Discussions were held with Outage management for outage schedule changes that could affect plant safety. No conflicts or significant problems associated with risk were identified .
- ORAM-TIP Safety Function Status information status board - The status board was displayed in the war room and color coded to indicate daily risk level. This board was used effectively throughout the outage and the risk conditions were discussed twice daily at the

turnover meetings. All personnel were informed on the level of risk for each Key Safety Function. The level of risk for each Key Safety Function was also maintained in the control room through the use of the Shutdown Protection Plan. This approach to safety information provided a consistent application to risk.

- No Shut Down Cooling Isolations occurred during RFO9. This is the third outage without any shutdown cooling isolations.

- Placement and record keeping of High Risk Impact Area Signs - Two individuals were assigned the task of ensuring the signs were installed and removed at the appropriate times throughout RFO9. The Safety Issues Group periodically inspected the location and placement of the High Risk Impact Area signs and found the placement to be more than adequate. A record of High Impact Area sign placement was kept in the Control Room and War Room and was initialed and dated each time a sign was installed or removed.

- ORAM-TIP risk profile graphs were updated daily by the Outage Scheduling Group. The updated profile aided in determining risk on a day-to-day basis and was used to predict risk for any schedule changes.

- Emergent Work - Emergent work was reviewed daily by the Safety Issues Group at the 1300 meeting. The Outage Management Team provided the review for the 0100 meeting. No items were identified that were outside of an existing outage window. Additionally, no items were identified that caused an increase to Core Damage or RCS Boiling Risk.

- During plant shutdown for RFO9, the plant experienced a problem entering the drywell. The outer drywell airlock door would not open due to an interlock problem associated with the drywell airlock inner door. The plan developed to get the seals depressurized provided the least risk to personnel and also provided the quickest method for entry into the drywell. This evolution was thoroughly thought out and planned by plant staff.

- After the start of RFO9 Entergy Mississippi determined that rework of all 500 kv breakers was necessary during the outage. This activity was a scope add and required a comprehensive review for its impact on outage risk. The Outage Scheduling Group and the switchyard coordinator proposed a coordinated work plan. A thorough review of the activities as they fit into the outage was performed by the Safety Issues Group and it was determined that there would be a minimal impact on the Electrical Key Safety Function. The risk impact was minimized due to the coordinated planning effort.

- ADHR ready for operation - The ADHR system fill, vent and flush was completed pre RFO9. All required surveillances were completed and the PSW side radiation monitor was placed in service. ADHR was placed in a modified isolation lineup per the SOI. This action allowed the ADHR system to be validated as an alternate SDC method shortly after entering mode 4.

- Communication of Risk Conditions - A PSRC meeting was held to discuss taking LPCS out of service before HPCS was returned to functional status. A presentation was made showing the before and after risk considerations. There were no significant changes in RCS Boiling Risk. Core Damage Risk indicated a doubling in value, but was still in the E-11 range. The PSRC approved releasing LPCS for suction strainer tie in and the remaining work on LPCS. This action allowed release of work and prevented an unneeded delay in outage activities.

PROBLEM AREAS

- The interlock problem with the drywell airlock inner door prevented plant staff from entering the drywell with the plant in mode 3 to identify any problems inside the drywell while the plant was still pressurized.

- The 'A' Recirculation pump was inadvertently tripped during a tagging evolution on one of the condensate pumps. The LFMG breaker was mistakenly opened instead of the condensate pump breaker. Following the inadvertent trip, the recirculation pump would not restart due to a problem with the limits on its associated FCV. CR 19980307 was written to document the event.

- The ECCS suction strainer segments did not meet the as built design specifications due to the inadequacy of the vendor's QA program. A decision was made to perform a 100% inspection of all strainer segments and validate them to our QA program. An Action Plan was put in place that consisted of a schedule for:

  - Inspections for hole elongation and weld quality
  - Development and issuance of a work order that included acceptance documentation for each segment.
  - Identification and scheduling of welders and welding inspectors
  - Implementation of the inspection/repair process for the strainer segments in the order in which they were to be installed in the plant.
  - Initiate Corrective Actions Reports for all identified discrepancies.

  The action plan commenced and continued around the clock until all segments were repaired, cleaned, inspected, and accepted. Some of the main issues associated with the suction strainers included:

  - Incomplete welds, inadequate welds, and missing welds
  - Unsatisfactory cleanliness
  - Over-sized holes in the perf-plate
  - Inadequacy of the Transco QA program

  The Containment Refuel Bridge and the Horizontal Fuel Transfer System continue to be sources of problems each refueling outage. Several delays were caused by equipment breakdowns during RFO9. This is a recurring problem each outage.

- The EPA breaker modification did not go well. The first breaker to be installed was on the alternate supply for RPS B. A lot of noise existed on the output of the regulator which was apparently causing fuses to blow when the EPA breaker was put in service. This modification was being made to increase the reliability of the EPAs to prevent inadvertent scrams. A decision was made to reinstall the old EPA breakers on the alternate supply for RPS B and run with them through Cycle 10. During Cycle 10 extensive testing will be done on the new EPA breakers to identify and correct problems then install them in RF10.

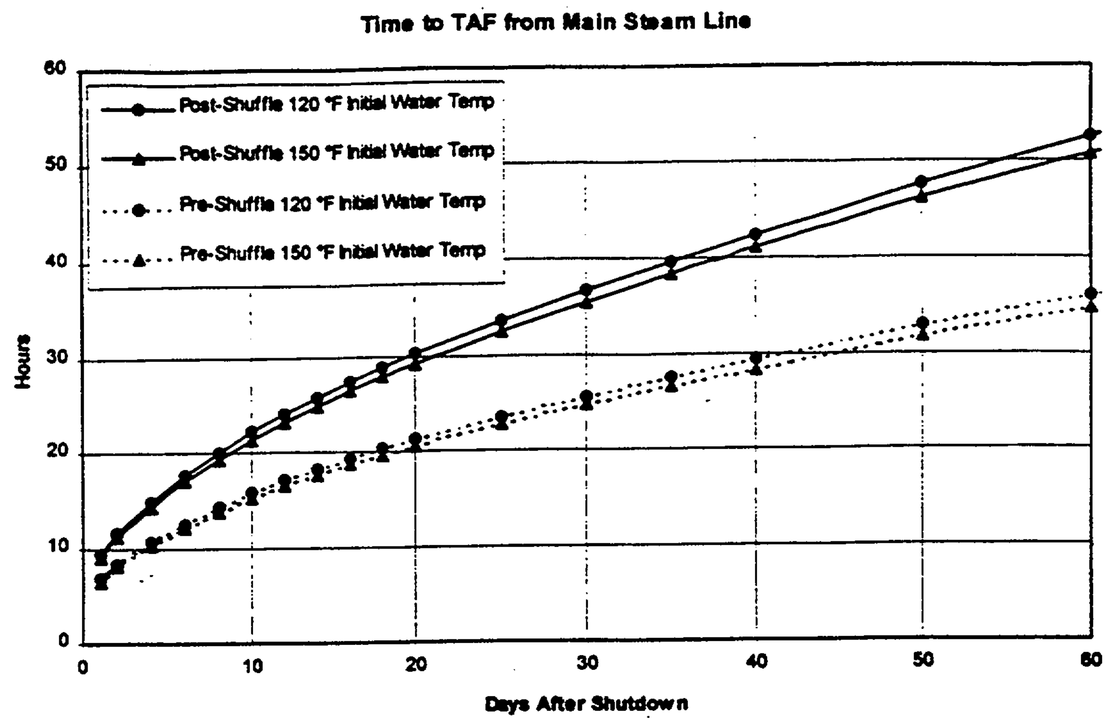
- GGCR1998037100 was written on 4/20/98 to document that the Franklin 500kv line had been out of service for about 24 hours due to storm damage. This was not known until the Pine Bluff dispatcher notified the Shift Superintendent that the line was to be reenergized at about 1600 on 4/18/98. This did not change the Key Safety Function condition or cause an unplanned entry into Technical Specifications or the TRM.

- Load oscillations were observed on the Division 2 DG during a maintenance run following adjustment of the lifters. The diesel was declared inoperative and a team was formed to identify and correct the problem. The MOP was removed and taken to the shop for testing. No apparent problem was found and the MOP was reinstalled. This event is very similar to the load oscillations observed in January of 1997 (Root Cause report 97-01). The Division 2 DG was repaired by replacing the governor control switch in the control room. Discussions with maintenance personnel indicate that no identifiable problem was found with the old switch. Division 2 DG ran with out any further oscillations.

- HPCS room cooler flush - During the room cooler flush small amounts of Co60 were found in the barrel and in the cooler. SSW C was tagged to prevent spread of contamination. The cooler was flushed until clear of contamination. Investigation determined that a contaminated hose was used for the flush.

- During the backup scram valve modification, air leaks were identified when the system was leak tested. The leaks persisted and it was finally determined that the cause of the leaks were due to an improper match up with the thread size on the valves. The leaks were determined to be caused by the valve having NPT (11½ threads per inch) on one end and English Standard (11 threads per inch) on the other end. Adaptors were procured and repairs made.

- While moving the shroud tool inspection ring from the RPV two of the lifting supports broke free allowing the ring to drop approximately 6 feet on that side. The ring was stabilized and a plan for recovery and removal was developed. The PSRC reviewed the 50.59 on the rigging issue and approved the plan. The shroud ring was lifted without any further incidents.


Time to TAF from Main Steam Line
Post-Shuffle 120 °F Initial Water Temp
Post-Shuffle 150 °F Initial Water Temp
Pre-Shuffle 120 °F Initial Water Temp
Pre-Shuffle 150 °F Initial Water Temp
Hours
0
10
20
30
40
50
60
Days After Shutdown
0
10
20
30
40
50
60

ORAM-TIP ASSESSMENT

The EPRI Outage Risk Assessment and Management and Technical Integration Package (ORAM-TIP) software was one of the tools used to assess the shutdown risk for RFO9. Outage scheduling information such as key plant activities, equipment availability, and their associated time frames were down-loaded from the outage scheduling software daily into the ORAM-TIP software. This information was then analyzed by the model to assess the Core Damage and RCS Boiling Risk associated with RFO9. The events considered for the Core Damage analysis are large or medium LOCAs, decay heat removal pump failures, SSW pump failures, shutdown cooling isolations, reactor pressure vessel isolations and loss of normal AC power. The RCS Boiling Risk analysis also utilizes these same events but additionally includes Division 1 and 2 AC bus failure events, shutdown cooling valve closure events, simple isolation events and instrument air failure events.

The ORAM-TIP model as performed average event frequency for RFO9 was:

- RCS Boiling 5.32×10^{-6} events/hour
- Core Damage 4.37×10^{-11} events/hour 2.85×10^{-8} events/year

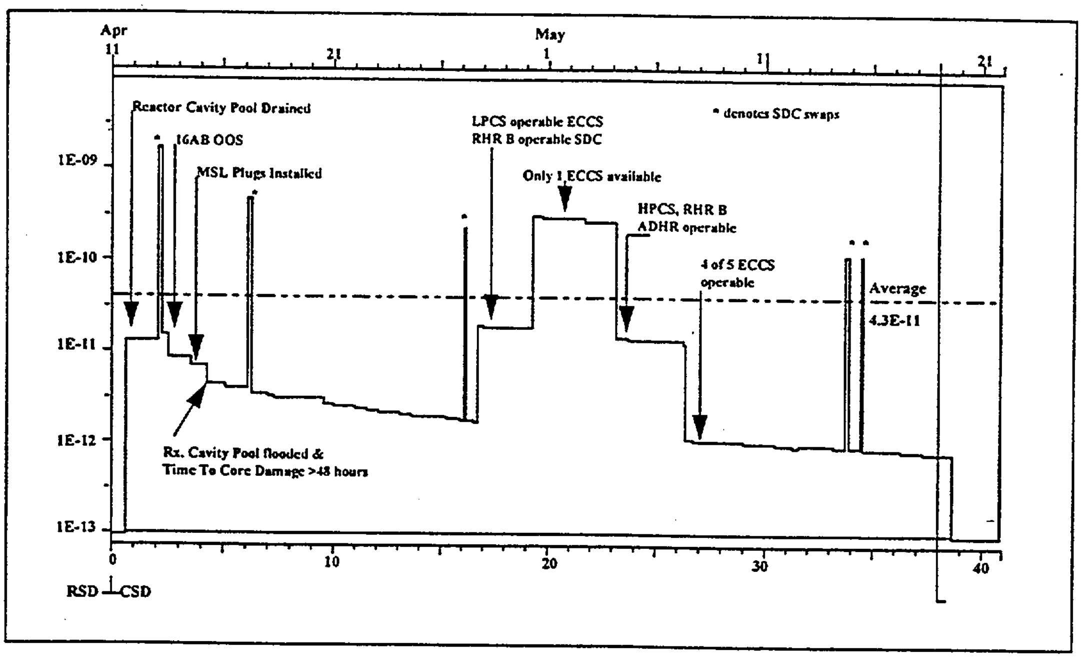
NUREG 1449, "Shutdown and Low Power Operation at Commercial Nuclear Power Plants in the United States," considers a core damage frequency of 1.0×10^{-4} to 1.0×10^{-6} events/year to be acceptable for shutdown and low-power operations. There are no guidelines for acceptability on the range of RCS Boiling. An as performed outage comparison of core damage frequency at GGNS is:

RFO	**events/hour**	**events/year**
RFO4	6.03×10^{-9} events/hour	$5.5 \text{ X } 10^{-6}$ events/year
RFO5	2.1×10^{-10} events/hour	6.5×10^{-7} events/year
RFO6	1.13×10^{-9} events/hour	1.6×10^{-6} events/year
RFO7	2.61×10^{-12} events/hour	2.8×10^{-9} events/year
RFO9	1.52×10^{-10} events/hour	1.0×10^{-7} events/year
RFO9	4.37×10^{-11} events/hour	2.85×10^{-8} events/year

CORE DAMAGE MODEL

The key sensitivities for Core Damage Risk were water inventory in the reactor cavity pool, decay heat levels, the potential for inadvertent drain down events and swapping decay heat removal systems. One change was made to the outage model to prevent the indication of an abnormal risk to the overall Core Damage and RCS Boiling risk profiles. This change allowed removal of the ECCS suction path from the Suppression Pool while still maintaining the respective decay heat removal system as available. Before this change was made, removal of the Suppression Pool suction path would cause the ECCS and decay heat removal function to be removed. The change to the ORAM model allowed a more realistic approach to managing shutdown risk.

The graph below displays the RFO9 as performed Core Damage Risk Profile and is very similar to the "as planned" Core Damage Risk Profile. The as performed Core Damage Risk shows a slight increase from a projected 1.85×10^{-11} events/hour to an actual 4.37×10^{-11} events/hour. This slight increase is caused by the April 30 through May 4 peak when only one ECCS was available for injection.



RFO9 AS PERFORMED CORE DAMAGE RISK PROFILE

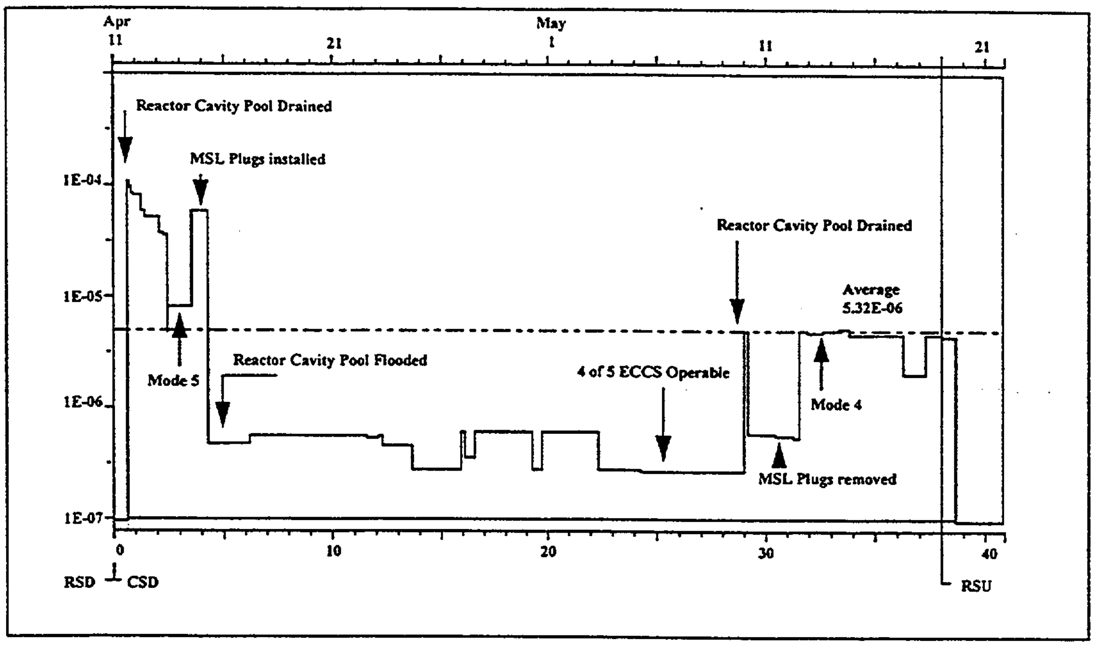
The first peak, days 1 & 2, occur due to the Reactor Cavity Pool being drained for removal of vessel internals, high decay heat levels and Bus 16AB being removed from service. These factors increase the Core Damage Risk due to the potential for a large or medium LOCA and the potential loss of decay heat removal. The risk drops when the plant enters Mode 5 primarily due to the change in the ORAM-TIP assumed temperature of 200 °F in Mode 4 to 140 °F in Mode 5.

Core Damage Risk continues a steady decrease following MSL plug installation and Reactor Cavity reflood until approximately mid-way through the outage. Risk once again increased to an E-11 value due to the removal of ECCS and the divisional swap. The highest peak during RFO9 occurs during this time frame as well when only one ECCS is available. This was an analyzed risk condition with RHR B in SDC, Division 2 DG operable, LPCS operable, and multiple off-site power sources available. No switchyard activities were allowed during this 5 day period.

The five short duration peaks that occur throughout RFO9 are caused by swapping decay heat removal systems. These peaks are controlled by an inadvertent drain down event and take into account the probability that the protective logic will not function properly and the probability that operators will not perform the evolution properly.

BOILING RISK MODEL

The following graph shows the as performed RCS Boiling Risk Profile for RFO9. The actual risk associated with RCS Boiling Risk for the outage was 5.32×10^{-6} events/hour. This is a substantial change from the projected value of 1.24×10^{-5} events/hour that was calculated for the as planned RFO9 Boiling Risk. The improvement can be attributed to the excellent planning of the RFO9 outage schedule to ensure adequate defense in depth was maintained for decay heat removal.



RFO9 AS PERFORMED RCS BOILING RISK PROFILE

As expected, the RCS Boiling Risk is relatively high at the beginning of the outage due to high decay heat in the reactor vessel. The RCS Boiling Risk graph reveals only two major peaks in the boiling risk frequency both of which are at the beginning of RFO9.

The first peak on day one was due to entering Mode 4 and draining the reactor cavity pool. The main initiators for RCS Boiling Risk are a RPV isolation event or a loss of decay heat removal event. The risk decreases when the plant enters Mode 5 due to the ORAM-TIP assumption that coolant temperature decreases to the technical specification limit of 140 °F when the mode change occurs.

The next peak is caused by installation of the main steam line plugs and remains at this level until the reactor cavity pool is flooded. The Boiling Risk during this time is controlled by a loss of divisional electrical power and failure of the decay heat removal pump and/or the SSW pump.

Two minor peaks occur toward the end of the outage. The first is when the Reactor Cavity Pool is drained and the second is when the plant enters Mode 4 following vessel reassembly.

CONCLUSIONS

Despite problems with the refueling floor equipment, diesel generator, ECCS suction strainers, recirculation pump flow control valve, erosion/corrosion piping and component replacement, and Main Turbine upgrade, RFO9 was the shortest refueling outage that GGNS has ever performed. RFO8 was performed in 41 days and RFO3 was completed in 44 days. All other refueling outages have be in excess of 52 days with the longest having a duration of 88 days (RFO1). The outage length can be attributed to excellent planning and teamwork by all personnel connected with RFO9.

RFO9 was also the best with respect to nuclear safety. The planning performed by the Outage Planning and Scheduling Group combined with the changes coordinated by the Outage Management Team prevented additional risk issues as schedule changes were made to accomodate unseen problems. These changes were made utilizing the ORAM-TIP outage risk software to predict the risk associated with the change. Another factor that aided in controlling risk issues was the utilization of the Operation Shutdown Protection Plan. The attachments were used by control room supervision to determine risk issues as plant conditions changed. The Safety Issues Group also constantly monitored the changes to the outage schedule to detect potential risk issues. These three independent checks provided an in-depth look at all changes to the outage schedule in a combined effort to detect potential risk issues.

RECOMMENDATIONS

Recommendations were identified as the outage progressed and were written up as Outage Critique Items.

Attachment 5

Date: March 26, 1998

To: J. J. Hagan

From: R. D. Ingram

Subject: NS&RA Report OA-98-01, Safety Assessment of the RFO9 Outage Schedule

GIN: 98-00519

Attached for your review is the Safety Issues Group's assessment of the RFO9 outage schedule.

GHL/ ghl

attachments: Report OA-98-01, Safety Assessment of the RFO9 Outage Schedule

cc:

J. G. Booth w/a
L. F. Daughtery w/a
W. A. Eaton w/a
C. E. Ellsaesser w/a
W. K. Hughey w/a
R. V. Moomaw w/a
J. C. Roberts w/a
C. D. Stafford w/a
M. J. Wright w/a
J. E. Venable w/a
File (NS&A) w/a
Central File, w/a [26]

NUCLEAR SAFETY & REGULATORY AFFAIRS
SAFETY ASSESSMENT SECTION

SAFETY ASSESSMENT OF THE RFO9 OUTAGE SCHEDULE

NS&RA REPORT NUMBER: OA-98-01

DATE: March 26, 1998

Prepared: ______________________ 3/26/98
Cognizant Engineer/Specialist **Date**

Approved: ______________________ 3/26/98
Safety Assessment Supervisor **Date**

EXECUTIVE SUMMARY

The Nuclear Safety and Regulator Affairs Safety Issues Group is required by NS&RA Section Procedure 09-S-03-14, Administration of ISEG Activities, to perform an assessment of the refueling outage schedule prior to starting the outage. The RFO9 Outage Schedule Assessment was performed using NUMARC 91-06, Guidelines for Industry Actions to Assess Shutdown Management, and other applicable industry documents as guides.

The purpose of the RFO9 Outage Schedule Assessment was to identify risk conditions and present the findings so that required contingency plans could be completed prior to the start of RFO9. A secondary purpose was to identify schedule improvements and provide immediate feedback to the Outage Scheduling Group as required.

The data used for the assessment utilized the March 9, 1998 RFO9 Outage Schedule and the ORAM-TIP model utilized the March 17, 1998 RFO9 Outage Schedule. There were no significant changes made to the March 17 schedule.

The assessment team performed a review of the Key Safety Functions (KSF) for Decay Heat Removal, Reactivity Control, Vessel Inventory Control, Containment Control and Electrical Power and also included a review of UFSAR events applicable to outage conditions - SBO, LOCA and Fire in the Control Room. The assessment team recognizes that a DBA LOCA is not possible during shutdown conditions, however, a DBA LOCA bounds all potential LOCAs and was therefore used as a worst case event. The single failure concept was used to determine risk conditions. If a single failure could result in the loss of a KSF, then a risk classification was assigned for the appropriate time frame.

Twenty-two days of the projected 34 day outage contain one or more risk conditions. By comparison, the RFO8 Outage Assessment contained a total of twenty-six days that had an associated risk condition. No risk conditions were identified with the Reactivity Control KSF or the UFSAR event analysis for a LOCA. The Decay Heat Removal KSF analysis identified a total of twenty-one days that contain a risk associated with the potential to lose SDC through a single fault. The ORAM-TIP model indicates that the average overall event frequency during the outage for RCS Boiling is 1.24 E-5 events/hour and for Core Damage is 1.85 E-11 events/hour. Contingency plans were recommended commensurate with the identified risk conditions for each KSF and UFSAR event and presented to plant staff for concurrence. Section 3.0 provides a detailed analysis of the KSFs and associated contingency plans.

The ECCS suction strainers will be replaced with a single large strainer during RFO9. The RFO9 Outage Schedule Assessment identified each ECCS strainer alignment and tie-in and factored it into the overall risk analysis. Additionally, the same information was incorporated into the ORAM-TIP risk model.

During RFO9 the Safety Issues Group will observe the outage schedule progression and provide input as necessary on schedule changes. Any major change to the schedule that meets re-evaluation criteria will be analyzed to determine if a risk condition exists. Additional contingency plans will be written as needed. Outage schedule changes will also be input into the ORAM-TIP outage risk model for evaluation of risk conditions.

Following RFO9, NS&RA Safety Issues Group will provide a post-outage critique that details the adequacy of the outage review including a comparison of planned to actual risk. The Outage Scheduling Group provides a daily update of the Outage Schedule and this is input into the ORAM-TIP model. The "as performed" ORAM-TIP model will be used as part of the post-outage assessment to provide a comparison between "as planned" to "as performed" risk. No recommendations were issued as a result of the RFO9 Outage Schedule Safety Assessment other than those contained within the contingency plans.

TABLE OF CONTENTS

1.0 INTRODUCTION

NS&RA Section Procedure 09-S-03-14, Administration of ISEG Activities, requires an assessment of the refueling outage schedule be performed prior to starting the outage. The RFO9 Outage Schedule Assessment was performed using the March 9, 1998 run of the outage schedule and the ORAM-TIP model utilized the March 17, 1998 RFO9 Outage Schedule. No significant changes were identified between the two runs of the outage schedule.

The purpose of the RFO9 Outage Schedule Assessment is to identify risk issues and to ensure that required contingency plans are in place prior to the start of the outage. Additionally, the review serves to identify any schedule improvements and provide feedback to the Outage Scheduling Group so that changes can be made to the outage schedule as required.

A day by day matrix was developed for each of the KSF (KSF) areas - Decay Heat Removal, Inventory Control, Reactivity Control, and Electrical Power Availability. An additional matrix was developed for selected UFSAR events that are applicable to shutdown conditions. All matrices are provided as attachments to this report.

2.0 METHODOLOGY

A list of critical systems and components associated with each KSF was developed and put into a matrix form that shows the dates associated with the unavailability of each system/component. The list of critical systems/components are located in Attachment 1, Tables 1 through 4. The tables were developed such that each would stand without reliance on any condition other than those listed on the specific table. A table exists for each of the KSFs analyzed, and contains all components, systems and plant conditions that are applicable to that KSF. The same system, component or plant condition was used on more than one table if it was applicable to that particular KSF.

In order to identify when a risk condition exists, a definition was developed for use during the outage schedule assessment. This definition is shown below.

A Risk Condition exists if one equipment failure or operator action can cause a loss of or a reduction in the plant's ability to:

a. remove decay heat,
b. provide electrical power,
c. maintain inventory control,
d. establish/maintain primary or secondary containment integrity when required, or
e. ensure adequate reactivity control.

Once factors affecting the KSFs were identified, the dates that the systems, components and/or plant conditions were not available for use were documented in each matrix. The tables were also reviewed against the final outage schedule to ensure that no significant schedule changes had occurred and that the analyzed data was still valid.

A comparison was made of the risks identified for RFO9 by the ORAM-TIP Risk Model and those identified by the assessment team. The purpose of the comparison was to provide a cross-validation of the assessment. Each analysis is performed independently and each uses different analysis techniques. When compared, the results of both analyses should be similar. If a similarity does not exist, an error may be indicated which would then lead to a re-analysis of that particular time in the outage. Graphs have been developed that show the comparison of the ORAM-TIP Model and the outage assessment team's findings.

An analysis of significant UFSAR transients and accidents is also performed as part of the RFO9 Outage Schedule Assessment. Those accidents and transients that may be applicable during outage activities are:

- Station Blackout
- Loss of Coolant Accident
- Fire

Attachment 1 Table 5 identifies those dates during RFO9 that each of the above transients could be applicable.

3.0 INVESTIGATION

Sections 3.1 through 3.5 present the risk conditions identified for each of the KSFs and UFSAR events along with the applicable contingency plans.

3.1 Reactivity Control Analysis

During an outage reactivity is controlled in several ways. These include the fuel movement plan, control rods, management of changes to the movement plan and personnel training.

Control rods, when fully inserted in the core, provide the neutron absorption needed to maintain the required Shut Down Margin (SDM). SDM is a value of negative reactivity required to be maintained at all times assuming the highest worth control rod is withdrawn from the core. Procedure 17-S-02-13, Control Rod Lifetime Estimation, provides assurance that the control rods do not become excessively depleted during operation prior to refuel. Additionally, the rod control system limits non-maintenance rod withdrawal to a single rod with the mode switch in the REFUEL position to prevent approaching the SDM limit. The reload analysis calculates a single rod withdrawal for all cells under the maximum reactivity conditions required by Technical Specifications and assumes worst case planned placement of fuel bundles. A conservative SDM is calculated by assuming that each cell contains the four highest worth bundles that could possibly occur among the four original and replacement bundles. Each calculated cell is analyzed for a rod withdrawal, either normal or inadvertent. In the event that adequate SDM is not calculated for a cell, it is designated to have one or more of its constituent assemblies removed and that location not reloaded until the remainder of the fuel shuffle is completed. This assures that, for these final cells, the highest worth configuration does not occur. These "SDM locations" are loaded with half blade guides to provide additional positive protection against loading of the locations inadvertently. Other analyses are also done to verify that the core remains substantially subcritical in the event of rotated or mis-located fuel assemblies during refueling, assuming no control blade withdrawal in the error cells.

GGNS uses computer-generated quality-controlled movement sheets to track and control the fuel during fuel movements. The important issue in movement control is the prevention of criticality by maintaining a minimum SDM. The assumption that the highest worth rod is withdrawn for SDM calculations provides protection against accidental single rod movement. The SDM value may be analytically or empirically determined.

In the case of the various pools where fuel may be stored, an infinite rack containing highest worth bundles is assumed. This is a worst case scenario which assures adequate subcriticality in the pools and the dry new fuel storage vault, if used. Boron loss and redistribution are also accounted for in the spent fuel pool.

Once fuel movement starts, the movement plan is controlled by an SRO. The movements are made by qualified, experienced personnel and checked by a representative of Reactor Engineering. The personnel representing Reactor Engineering on the refuel floor during vessel fuel movements have completed training associated with fuel tracking, movement and verification.

To ensure proper reactivity control during the outage and post-outage, several procedures are used. These procedures are:

- 17-S-02-5, Post Refueling Recirculation System Flow Instrumentation Calibration
- 17-S-02-13, Control Rod Lifetime Estimation
- 17-S-02-100, Criticality Rules
- 17-S-02-108, Core Loading Verification
- 17-S-02-300, Special Nuclear Material Movement and Inventory Control

During RFO9, 34 control rods will be replaced. Control rod blade replacement is adequately controlled by procedure 04-S-03-C11-1, Control Rod Blade Removal And Installation. Technical Specification limitations require that the fuel must be unloaded around control blades that are being removed and that no fuel loading take place unless all control blades are fully inserted. This requirement is controlled by the movement sheets.

A review of the outage schedule shows no indication of an unacceptable or unanticipated risk concerning reactivity control. Additionally, the requirements of Technical Specifications concerning reactivity control have been adequately addressed and met. The systems and/or plant conditions used to assess reactivity control can be found in Attachment 1, Table 1.

3.2 Inventory Control Analysis

The Inventory Control KSF was analyzed and risk conditions were identified for five days during RFO9. The remaining days of the outage do not pose any risk conditions due to the availability of a minimum of two ECCS in separate divisions throughout the outage. The systems and/or plant conditions used to assess Inventory Control are contained in Attachment 1, Table 2.

4/17-21 **A RISK CONDITION EXISTS FOR 4/17 through 4/21** due to a potential fault that results in a loss Bus 15AA. The Reactor Cavity Pool is flooded, ADHR is in service and Division 2 and 3 ECCS are unavailable during these days. An electrical fault that affects 15AA could cause an extended loss of Division 1 ECCS.

CONTINGENCY PLAN: ONEP 05-1-02-I-4, Loss of AC Power, ONEP 05-1-02-III-1, Inadequate Decay Heat Removal, and Emergency Procedure, EP-2 RPV Control.

NOTE

In addition to posting Division 1 ECCS and electrical equipment as "protected equipment" all evolutions that have a potential to drain the RPV or upper pools should be suspended during these dates.

3.3 Power Availability Analysis

The systems and/or plant conditions used to perform the Power Availability analysis can be found in Attachment 1, Table 3.

The Power Availability Analysis criteria for evaluating each day considered the following:

* A single component failure which causes a loss of BOP or ESF power is considered a RISK and would require a CONTINGENCY PLAN,

* Power availability was considered unacceptable if at least one on-site or two off-site power sources were not maintained.

4/15 - 20 **A RISK CONDITION EXISTS ON 4/15 through 4/20.** ST11 and ESF 11 are removed from service. A fault that causes the loss of ST21 will cause a loss of all BOP as well as a loss of ESF power for those buses not being powered from ESF 12. A loss of BOP power during this time will cause a loss of SDC since ADHR is providing the SDC function. Precautionary actions should be taken to protect the power supply to ESF bus 15AA to prevent loss of the availability of Division 1 ECCS for injection into the RPV. Additional precautions should be taken to prevent power loss to the 16AB bus to prevent inadvertent isolations.

CONTINGENCY PLAN: ONEP 05-1-02-I-4, Loss of AC Power. Additionally, the area around Division 1 D/G, ST21, ESF 21 and associated feeder breakers should be posted with "protected equipment" signs and no work should be performed on or around this equipment.

4/27 - 5/1 **A RISK CONDITION EXISTS ON 4/27 through 5/1.** ST21 and ESF 21 are out of service. A single fault that causes a loss of ST11 will cause a complete loss of BOP power and ESF power not being supplied by ESF 12.

CONTINGENCY PLAN: ONEP 05-1-02-I-4, Loss of AC Power. Additionally, the area around ST11, ESF 11 and their associated feeder breakers, and Division 2 and 3 D/Gs should be posted with "protected equipment" signs and no work should be performed on this equipment until ST21 is returned to service.

ADDITIONAL CONSTRAINTS DURING SWITCHYARD MAINTENANCE

* Switchyard activities are in progress from 4/15 through 4/20 and 4/27 through 5/1. During these times, the pedestrian/vehicular traffic in the general switchyard and more specifically in the area around the Service Transformers and associated breakers should be posted for increased awareness.

* The area around the AVAILABLE Station Transformer and any single failure breakers should be conspicuously posted as the single plant off-site power source. Also, if for any reason the on-site power source becomes INOPERABLE, all switchyard activities should be halted.

3.4 Decay Heat Removal Analysis

The majority of the risk conditions during RFO9 are attributed to loss of the Decay Heat Removal KSF. Attachment 1, Table 4 is a listing of systems, components and plant conditions that were considered during the analysis.

4/11 - 12 **A RISK CONDITION EXISTS on 4/11 &12** due to a potential fault that causes a loss of the common suction. The reactor cavity pool is drained and ADHR is in service via the RHR A suction. A fault on bus 14AE or a loss of the RPV common suction path will result in a loss of SDC.

CONTINGENCY PLAN: ONEP 05-1-02-III-1, Inadequate Decay Heat Removal

4/13 - 14 **A RISK CONDITION EXISTS on 4/13 & 14** due to a potential fault that causes a loss of the common suction, a loss of Bus 15AA or a loss of Bus 14AE. The Reactor Cavity Pool is still drained, Bus 16AB is out of service and the MSL plugs are installed. ADHR is the operating SDC system with RHR A, LPCS and HPCS available. The MSL plugs are installed late on 4/13 with completion of pool flood scheduled for approximately 24 hours later. During this 24 hour period **Time to Boil ranges from < 1 hour with RPV level at the MSLs to slightly > 1 hour with RPV level at the flange to ~ 5 hours with the pool flooded.** A loss of the common suction line from the RPV would remove all normal means of decay heat removal and could require re-flooding the reactor cavity pool in order to establish a communications path with the suppression pool for the removal of decay heat. Personnel and tools/equipment in the reactor cavity pool and suppression pool must be removed prior to flooding the reactor cavity pool. **Extreme precautions should be taken during the time that RPV level is at or below the vessel flange.**

CAUTION

Should the need arise, a coordinated effort will be required to evacuate personnel from the 208' Containment elevation and the suppression pool and to ensure the removal of equipment and tools from the reactor cavity pool in order to re-flood the reactor cavity pool. Pre-planning should be performed to ensure that all individuals working on the 208' Containment elevation and suppression pool are prepared to take appropriate actions.

CONTINGENCY PLAN: ONEP 05-1-02-III-1, Inadequate Decay Heat Removal and/or ONEP 05-1-02-I-4, Loss of AC Power. Bus 15AA, Bus 14AE and Division 1 DG and associated ECCS should be posted as "protected equipment".

4/15-20 **DUAL RISK CONDITIONS EXIST FOR 4/15 through 4/20** due to a single failure that causes the loss of ST21/ESF21, Bus 14AE, Bus 28AG, or a loss of the spent fuel pool common suction. ST11, ESF11, 18AG, and the E12-F008 and F009 valves are tagged for maintenance. The Reactor Cavity Pool is flooded and ADHR is the operating SDC system with suction from the Spent Fuel Pool. A fault that causes a loss of ST21 would result in a loss of off-site power with the exception of those loads powered from ESF12. Additionally, a loss of the common suction from the spent fuel pool will result in a loss of SDC. During the time that ADHRS is in service using the spent fuel pool suction path, vessel temperature monitoring by use of in-vessel thermocouples is required. Division 1 ECCS and DG are operable.

CONTINGENCY PLAN: ONEP 05-1-02-III-1, Inadequate Decay Heat Removal and/or ONEP 05-1-02-I-4, Loss of AC Power. ST11, ESF11, Bus 28AG, Bus14AE and Division 1 DG and associated ECCS should be posted as "protected equipment".

4/27-28 **A RISK CONDITION EXISTS FOR 4/27 & 28** due to a potential loss of Bus 16AB, RHR B, SSW B, or ST11/ESF11. RHR B is running in SDC, HPCS is operable and both Division 1 and 3 DGs are operable. ST21/ESF21, RHR A, SSW A, LPCS, RHR C and ADHR are removed from service for maintenance. A fault that causes the loss of ST11/ESF11 would cause a loss of power to all loads not supplied by ESF12. Likewise a fault on Bus 16AB or a fault that causes the loss of either the RHR B or SSW B pumps would result in a loss of SDC. During these dates the time to boil is approximately 13 hours with the upper pool flooded.

CONTINGENCY PLAN: ONEP 05-1-02-III-1, Inadequate Decay Heat Removal and/or ONEP 05-1-02-I-4, Loss of AC Power. ST11, ESF11, Bus 16AB and Division 3 should be posted as "protected equipment".

4/29-5/1 **A RISK CONDITION EXISTS ON 4/29, & 30,** due to a single failure which causes a loss of ST11, ESF11, Bus 16AB or the RHR B/SSW B pumps. The RHR C and ADHR systems are available, however, RHR A, and ST21/ESF21 remain tagged out for maintenance. An electrical fault that affects Bus 16AB or ST11/ESF11 will cause a loss of decay heat removal. ESF 12 and HPCS with Division 3 DG are also available during these dates. LPCS is available on 5/1.

CONTINGENCY PLAN: ONEP 05-1-02-III-1, Inadequate Decay Heat Removal and/or ONEP 05-1-02-I-4, Loss of AC Power. ST11, ESF11 and Division 2 & 3 ECCS and electrical components should be posted as "protected equipment".

5/5-8 **A RISK CONDITION EXISTS ON 5/5 through 8** due to the potential loss of the common shutdown suction from the RPV. The Reactor Cavity Pool is drained and **Time to Boil is ~ 3 hours with RPV level at the MSLs and ~ 4 hours with RPV level at the vessel flange**. RHR B is running in SDC with ADHR and RHR C available. Division 2 & 3 ECCS are available with their associated DGs and Division 1 ECCS is functional. A loss of the RPV common suction path could require reflooding the Reactor Cavity Pool in order to establish a communications path with the suppression pool for the removal of decay heat. Personnel in the reactor cavity pool and the suppression pool along with tools and equipment must be removed prior to flooding the reactor cavity pool.

CONTINGENCY PLAN: ONEP 05-1-02-III-1, Inadequate Decay Heat Removal

CAUTION:

Should the need arise, a coordinated effort will be required to evacuate personnel from the 208' Containment elevation and the Suppression Pool and to ensure the removal of equipment and tools from the reactor cavity pool in order to re-flood the reactor cavity pool. Pre-planning should be performed to ensure that all individuals working on the 208' Containment elevation and in the Suppression Pool are prepared to take appropriate actions.

5/9-10 **A RISK CONDITION EXISTS ON 5/9 & 10** due to the potential loss of the RPV common suction or loss of RWCU/CCW during the Ops Hydro. The Reactor Cavity Pool is drained and the plant is scheduled to enter Mode 4 on 5/9 in conjunction with the Ops Hydro. RHR B is running in SDC until the Ops Hydro preparations begin. RWCU and CCW will be used to control reactor temperature during the hydro and all ECCS with the exception of RHR B are operable. RHR B will be inoperative for about 2 days (5/9&10) for suction strainer connection.

CONTINGENCY PLAN: ONEP 05-1-02-III-1, Inadequate Decay Heat Removal.

3.5 UFSAR Event Analysis

The UFSAR was reviewed for those accidents/transients that may be applicable during an outage and for outage activities that may have altered the design configuration. Station Blackout, Loss of Coolant Accident, and Fire were determined to require further review.

The UFSAR analysis is an "event based" approach in identifying risk conditions instead of a "component based" approach as was used for the KSFs. Contingency plans are shown for the risk conditions identified for SBO, LOCA, and Fire. The actions taken by the operators will not be as obvious as those used for the KSF single failure faults due to the multiple faults that occur in these three events. The contingency plans identified for SBO, LOCA and Fire are designed to make the operator aware of the special conditions surrounding the event and to aid them in making proper decisions during shutdown conditions while using ONEPs, EPs, or temporary procedures.

3.5.1 Station Blackout

Assumption: The SBO lasts for 8 hours. The issue for SBO becomes core boiling, and with core boiling, Secondary Containment is not valid because the SBGTS is not available, therefore, Primary Containment is the only viable control.

Conclusion: If the upper pools are not flooded and with Primary Containment not set, SBO is a viable accident during shutdown.

4/11-13 **A RISK CONDITION EXISTS FOR SBO ON 4/11 - 4/13** due to low water level conditions. An SBO will remove all normal means of decay heat removal, however, the HPCS and its associated D/G are available on a continuous basis during these dates.

CONTINGENCY PLAN: ONEP 05-1-02-I-4, Loss of AC Power and ONEP 05-1-02-III-1, Inadequate Decay Heat Removal.

5/5-8 **A RISK CONDITION EXISTS FOR SBO ON 5/5 - 5/8** due to a low water level in the Reactor Cavity Pool. The HPCS D/G is available to supply necessary power to Division 1 or 2 electrical bus and energize required ECCS pumps for decay heat removal. All ECCS are available during this time frame.

CONTINGENCY PLAN: ONEP 05-1-02-I-4, Loss of AC Power and ONEP 05-1-02-III-1, Inadequate Decay Heat Removal.

3.5.2 Loss Of Coolant Accident

The assessment team recognizes that a DBA LOCA is not possible during shutdown conditions, however, a DBA LOCA bounds all potential LOCAs and was therefore used as a worst case event.

Assumptions: One or more ECCS are operable and the LOCA is due to a double ended shear of the Recirculation suction piping, then: the issue for LOCA becomes <u>core damage</u>.

<u>Conclusion:</u> Reactor water level must be maintained equal to or greater than TAF to prevent fuel damage, therefore: A risk exists when the lower containment hatches and doors are open. This is compounded when lines and hoses obstruct the rapid closure of these openings thereby making it extremely difficult to flood the containment to a water level at or above TAF.

There are two ways to provide adequate core cooling in this situation.

1. Seal the containment and flood to >TAF, or
2. Establish a flow path from the Suppression Pool through the reactor vessel and back to the suppression pool over the weir wall or through the drywell equipment hatch and door.

In order to establish a recirculation path, either the upper pools must be flooded and suppression pool level >12.67 feet or, during low water level conditions, the Suppression Pool level must be >18.34 feet and HPCS with CST suction available. Since containment integrity is not set during the majority of a refueling outage, this combined with a low water level condition (Reactor Cavity Pool drained) and suppression pool level <12.67 feet or suppression pool level >18.34 feet and HPCS not available dictate the days in the outage that are considered to be a risk with respect to a LOCA.

At no time during RFO9 will the Suppression Pool be at a level or equivalent level of less than ≈17 feet during the times that the Reactor Cavity Pool is drained. Additionally, during both time frames when the upper cavity pool is drained, the HPCS is operable. On the basis of above criteria no LOCA concerns exist for RFO9.

3.5.3 Fire

A risk condition due to a fire exists when the Division 1 equipment is out of service. This is due to Division 1 being the division that is protected during a fire in the control room. The risk condition only applies to a fire in the control room. The days associated with a fire risk are **4/27, 28, 29, & 30**.

<u>4/27-30</u> **A RISK CONDITION EXISTS ON 4/27 THROUGH 30** due to the potential of a fire in the Control Room that affects the Division 2 equipment with a major portion of Division 1 equipment being out of service during these dates. Should a fire occur during this time the ability to maintain cold shutdown could be lost due to a fire in the control room. A fire that affects Division 2 could remove the plants ability to operate a single division from the Remote Shutdown Panel.

<u>CONTINGENCY PLAN:</u> Implement applicable portions of ONEP 05-1-02-II-1, Shutdown from the Remote Shutdown Panel and refer to and implement the appropriate Decay Heat Removal contingency plans for the applicable dates.

Additionally, precautions should be taken to protect the Division 2 equipment from potential fire hazards. These actions should include daily tours by plant fire protection personnel to identify fire hazards located in and around the Division 2 equipment and Division 2 cable trays/raceways located in general traffic areas in the plant. Absolute control must be maintained of Cutting, Grinding and Welding Permits in and around Division 2 equipment. The Division 2 equipment, cable trays and raceways areas should be posted with "protected equipment" signs and roped off as necessary to warn personnel of the significance of the equipment.

3.6 ORAM-TIP Model vs. Shutdown Risk Analysis Comparison

The EPRI Outage Risk Assessment and Management Technical Integration Package (ORAM-TIP) software is one of the tools used to assess the shutdown risk for RFO9. Outage scheduling information such as key plant activities, equipment availability, and their associated time frames is down-loaded from the outage scheduling software into the ORAM-TIP software. This information is then analyzed by the ORAM-TIP software model to provide an assessment of the Core Damage and RCS Boiling Risks associated with the outage activities. Some of the events considered for the Core Damage analysis are loss of decay heat removal, loss of normal AC power, large or medium LOCA, SSW pump failures, shutdown cooling isolation events, reactor vessel isolation events, and draindown events. In addition to these, the RCS Boiling Risk analysis also considers Division 1 and 2 AC/DC bus failures.

The probabilistic shutdown safety assessments (PSSA) module within ORAM provides a probabilistic risk assessment (PRA) like approach to analyzing outage related risk profiles. The PSSA is the primary process that generates the risk-related information used in viewing the outage, and in particular the Core Damage Risk and RCS Boiling Risk graphs.

The ORAM-TIP model indicates that the average overall event frequency during the outage for RCS Boiling Risk is 1.24 E-05 events/hour and for Core Damage Risk is 1.85 E-11 events/hour. This Core Damage Risk average is caused by the potential for a large or medium LOCA throughout RFO9. As in past outages, the risk for RCS Boiling in RFO9 is significantly greater than that of Core Damage.

3.6.1 Core Damage

Figure 1 shows the Core Damage Risk for RFO9 based on the current outage schedule. The key sensitivities are water inventory in the reactor cavity pool, decay heat levels, normal AC power availability, and the potential for inadvertent drain down events while swapping decay heat removal systems. Review of Figure 1 reveals a curve that follows the decrease in decay heat levels over the outage with four short duration peaks in Core Damage frequency.

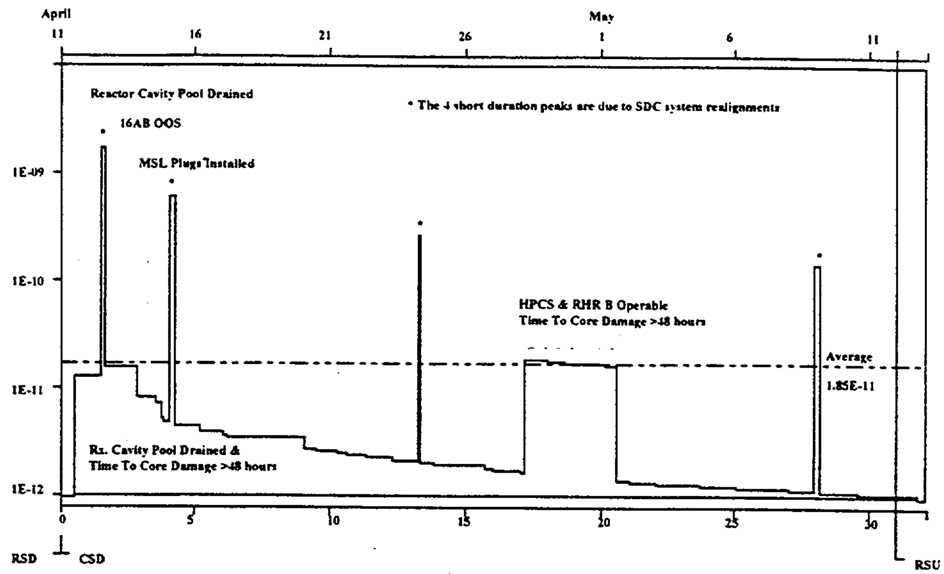


Figure 1 RFO9 Core Damage Risk Profile

The highest values for Core Damage Risk occur between April 11 through April 14 and April 27 through May 1. April 11 through April 14 the Reactor Cavity Pool is drained for removal of RPV internal components. During these dates the decay heat levels are high and Division 2 ECCS is removed from service. The initial high peak is due to ADHR being placed in service and Core Damage is based on an inadvertent drain down event. From this initial peak on 4/11 up to and including the second peak when ADHR suction is shifted to the spent fuel pool, the Core Damage Risk values change from 1.25 E-11 events/hour to 4.65 E-12 events/hour on 4/14 when the Reactor Cavity Pool is flooded. The contributors to Core Damage Risk during this time are a large/medium LOCA and loss of normal AC power with a large/medium LOCA being the major contributor. A decrease in Core Damage Risk occurs on 4/13 when the MSL plugs are installed. This decrease to 8.06 E-12 is caused by the removal of 4 large drainage paths from the RPV for LOCA considerations.

On 4/14 the Core Damage Risk profile decreases to 4.25 E-12 due to the time to reach Core Damage exceeding 48 hours. The continual reduction in Core Damage Risk is due to the reducing reactor decay heat levels with the main contributor to Core Damage Risk being a large/medium LOCA.

A second peak occurs between 4/27 and 5/1. This peak is due to only having HPCS available for injection with RHR B running in SDC. The Time to Core Damage remains >48 hours during this time.

3.6.2 RCS Boiling Risk

Figure 2 is the RCS Boiling Risk profile for RFO9. As expected, the RCS Boiling Risk is relatively high at the beginning of the outage due to high decay heat loads.

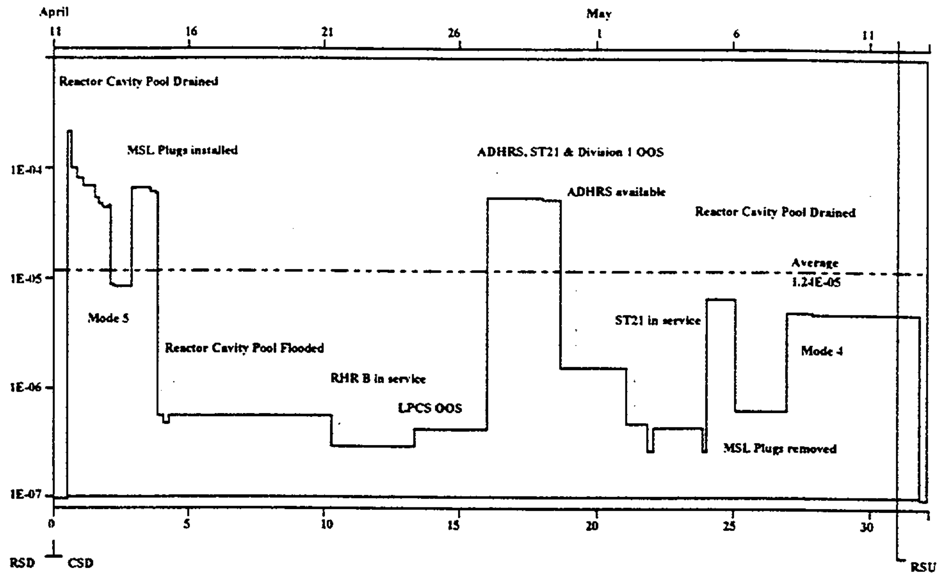


Figure 2 RFO9 RCS Boiling Risk Profile

The first peak occurs on April 11 when the RCS Boiling Risk increases to 2.14 E-4 events/hour due to entering Mode 4 and draining the Reactor Cavity Pool. The main initiators for RCS Boiling Risk are a RPV isolation event, a decay heat removal pump failure, and a SDC suction line isolation event. The ORAM-TIP program uses a default value of 200° F while the plant is in Mode 4.

The risk decreases slightly to 4.7 E-5 events/hour until Mode 5 is entered. When Mode 5 is entered, the risk drops to 8.35 E-6 events/hour because the calculated time to RCS Boiling increases due to ORAM-TIP's assumption that RCS temperature decreases to the technical specification limit of 140° F when the mode change occurs.

The next peak for RCS Boiling Risk occurs when the Main Steam Line plugs are installed. The risk increases to 6.3 E-5 events/hour and remains at this level until the Reactor Cavity Pool is flooded. Pool flood causes a decrease in RCS Boiling Risk to 5.52 E-7 events/hour. The boiling risk during this period is controlled by a simple RPV isolation event, a Division 1 AC bus failure, and a decay heat removal pump failure event.

RCS Boiling Risk remains in the mid E-7 range until 4/27 when the Division 1 equipment is removed from service . The 4/27 peak in RCS Boiling Risk equates to 5.37 E-5 and remains at this level until the ADHRS is returned to an available status on 4/29 and risk decreases to 1.57 E-6 events/hour. A second decrease in RCS Boiling Risk occurs on 5/1 (4.6 E-7 events/hour) when ST21 is returned to service.

RCS Boiling Risk increases to 6.4 E-6 events/hour on 5/5 due to the Reactor Cavity Pool being drained to facilitate reinstallation of vessel components. The final decrease in RCS Boiling Risk occurs on 5/6 when the MSL plugs are removed (6.1 E-7 events/hour).

The final peak causes the risk to increase to 4.8 E-6 events/hour and is caused by the plant entering Mode 4. The main contributors to RCS Boiling Risk between May 4 and Mode 2 are a SDC isolation event and a RPV isolation event. The RCS Boiling Risk increase to this value is primarily due to ORAM-TIP model assuming a higher RCS temperature of 200° F.

3.6.3 Comparison of The Two Risk Assessment Models

The ORAM-TIP model indicates that the overall event frequency for RCS Boiling Risk during RFO9 is 1.24 E-5 events/hour and for Core Damage Risk 1.85 E-11 events/hour. As in past outages, the risk associated with RCS Boiling in RFO9 is significantly greater than that of Core Damage. Figures 3 and 4 below provide a comparison of all risk conditions identified during RFO9 on a daily basis. Both graphs contain the same information but are presented in two distinct formats for ease of viewing, The identified risks shown in Figures 3 and 4 include those associated with the KSFs, Inventory Control, Electrical Power Availability, and Decay Heat Removal, and the three UFSAR events, Fire in the Control Room, SBO, and LOCA. No risk conditions were associated with LOCA concerns as explained in Section 3 of this report.

Figure 3 is a stacked bar chart that shows the total number of identified risks per day during RFO9 by contributor category. The KSF Risk bar is a summation of the risks associated with the Inventory Control, Electrical Power, and Decay Heat Removal KSFs.

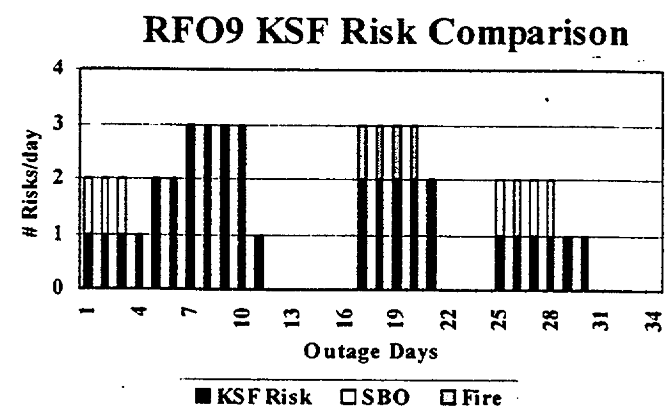


Figure 3

Figure 3 shows that the KSFs provide the most risk contributors. The potential for a an event which causes the loss of decay heat removal during RFO9 is the largest single contributor to the total number of risk days. Twenty-one days of the outage have a risk condition associated with the Decay Heat Removal KSF. The specific dates and contingency plans for each risk condition identified in Figure 3 are contained in Section 3 of this report.

Figure 4 is a line chart that represents the summation of the risks contained in Figure 3. Figure 4 is typical of past refueling outages. The number of risks per day are high at the beginning of the outage, usually the first 10 days, and again at the point of divisional swap. The three peaks are caused by a combination of risks associated with the KSFs and UFSAR events. The first peak, day 7 through 11, is associated with KSF for Decay Heat Removal, Inventory Control and Electrical Power. The second peak represents risk events associated with the KSF for Decay Heat Removal and Electrical Power and a fire in the control room. The final peak on day 25 through 28 is due to the Decay Heat Removal KSF and the potential for a SBO due to the upper pool being drained. Adequate contingency plans have been developed for these peak periods of risk conditions and are contained in Sections 3.1 through 3.5 of this report.

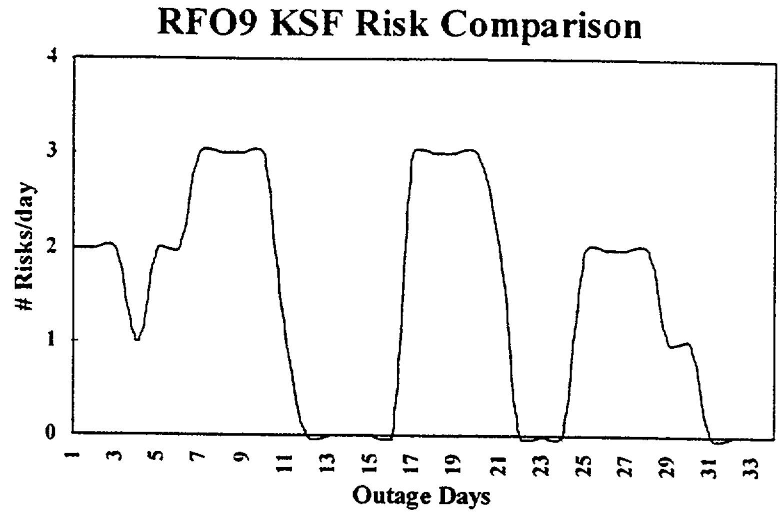


Figure 4

No inexplicable variations between the two sets of graphs, Figures 1/2 and Figures 3/4, exist. This indicates the two methods of assessing risk conditions for RFO9 reached the same basic conclusions. This comparison provides a cross-validation for each method used in the assessment.

The ORAM-TIP model and the RFO9 Outage Schedule tables will be utilized to re-analyze significant schedule changes as they arise during RFO9.

4.0 CONCLUSIONS

As in previous refueling outages, the NS&RA Safety Issues Group used the concept of single failure to determine risk conditions. If a single failure would result in the loss of a required system or function, then a risk condition classification was assigned for the appropriate time frame. Sections 3.1 through 3.5 of this report have identified the risk conditions associated with the KSFs and selected UFSAR events. Appropriate contingency plans are also contained within these same sections for each identified risk condition.

During RFO9 the ECCS suction strainers will be replaced with a single large strainer. The strainer is a 360° strainer that will be installed in segments. Each segment will be "floated" to its respective location, placed on the floor of the suppression and bolted to its adjacent segment. The 50.59 associated with the design and implementation of the strainer installation has been approved by the PSRC. Additionally, the installation process including strainer segment alignment, final bolt up to the respective ECCS pump and system retests have been incorporated into the RFO9 Outage Schedule. The RFO9 Outage Schedule Assessment identified each ECCS strainer alignment and tie-in and factored it into the overall risk analysis. Additionally, the same information was incorporated into the ORAM-TIP risk model. Discussions have been held with the personnel implementing the suction strainer modification and appropriate precautions are being put in the work instructions to act as a reminder when moving the segments in the area of operable/functional ECCS. The actual implementation and movement plan for the suction strainers will be thoroughly reviewed by the project manager and responsible engineer prior to and during installation. The PSRC will review and approve the overall work/contingency plan for the installation. The PSRC will indicate any events which would require stopping work and waiting for their approval to continue.

The ORAM-TIP model indicates that the average overall event frequency during RFO9 for RCS Boiling is 1.24 E-05 events/hour and 1.85 E-11 events/hour for Core Damage Risk. The average risk value in RFO9 for RCS Boiling Risk is approximately the same as the final RCS Boiling Risk for RFO8 (1.13 E-5 events/ hour). The RFO9 Core Damage Risk Profile is approximately 8 times lower that the final RFO8 Core Damage Risk (1.52 E-10 events/hour). The decrease in Core Damage Risk in RFO9 is due to the absence of operations with a potential to drain the RPV. CRD mechanisms were rebuilt during RFO8 and none are scheduled for RFO9.

Twenty-two days of the projected 34 day outage contain one or more risk conditions. Of the areas reviewed, the Reactivity Control KSF had no safety concerns and the Decay Heat Removal KSF analysis identified the largest number of risk condition days. Contingency plans were written commensurate with the identified risk conditions.

In addition to the contingency plans listed in sections 3.1 through 3.5, the practice of "posting" the operable/functional train or equipment used in past refueling outages should be continued. Special consideration should be given to posting those electrical panels that contain normal power or logic power for shutdown cooling and the shutdown cooling isolation logic.

During the outage, NS&RA will make observations concerning how the outage schedule is being implemented. Any major changes to the outage schedule that meet the re-evaluation criteria of Plant Administrative Procedure 01-S-06-42 will be scrutinized to ensure additional risk conditions do not develop and that the changes do not add unacceptable risks. These changes will also be input into the ORAM-TIP model for confirmation on risk conditions. The group will also attend outage scheduling meetings to ensure emergent work activities are addressed from a risk perspective.

5.0 RECOMMENDATIONS

No specific recommendations other than those contained in the contingency plans were issued as a result of the RFO9 Outage Schedule Safety Assessment.

6.0 ATTACHMENT

The following pages contain Attachment 1 Tables 1 through 5. These tables show the times that equipment and systems necessary to meet one of the KSFs are not available to perform that function. Tables 1 through 5 were use to analyze the RFO9 Outage Schedule for risk conditions. The blacked out days on Tables 1 through 5 indicate that the associated equipment is out of service or that the applicable condition is not met.

Attachment 1 Table 1 **Reactivity Control Key Safety Function**

RFO9 Start: 4/11/98	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	1	2	3	4	5	6	7	8	9	10	11	12	13	14
All Rods In	ALL RODS FULLY INSERTED																																	
SBLC A																																		
SBLC B																																		
In Core Fuel Movements																																		
CRD Removal																																		
Core Alterations																																		
SRMs																																		
Under Vessel Activities																																		
C11 System																																		
Shorting Links	INSTALLED																																	
RFO9 Start: 4/11/98	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Outage Day	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34

ATTACHMENT 1 TABLE 2 INVENTORY CONTROL KEY SAFETY FUNCTION

RFO9 Start: 4/11/98	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	1	2	3	4	5	6	7	8	9	10	11	12	13	14
HPCS																																		
HPCS D/G																																		
Buss 17AC																																		
LPCS																																		
LPCI A																																		
SSW A																																		
Buss 15AA																																		
DIV 1 D/G																																		
LPCI B																																		
Buss 16AB																																		
DIV 2 D/G																																		
SSW B																																		
LPCI C																																		
RWST Pumps																																		
Condensate System																																		
CRD System																																		
Firewater System																																		
Demin Water																																		
SBLC																																		
CRD Removal																																		
Secondary Ctmt. Broken					Secondary Containment Set (SCS)																												SCS	
Upper Pools Drained				Upper Pool Flooded (UPF)																												UPF		
Sup. Pool Lvl <12' 8"																																		
RFO9 Start: 4/11/98	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26.	27	28	29	30	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Outage Day	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34

ATTACHMENT 1 TABLE 3 POWER AVAILABILITY KEY SAFETY FUNCTION

RFO9 Start: 4/11/98	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	1	2	3	4	5	6	7	8	9	10	11	12	13	14
DIV. 1 D/G																	■	■	■	■	■	■	■	■	■	■								
BUSS 15AA																																		
DIV. 2 D/G	■	■	■	■	■	■	■	■	■	■	■	■																						
BUSS 16AB			■	■																														
DIV. 3 D/G							■	■																										
BUSS 17AC																																		
ESF 11					■	■	■	■	■	■																								
ESF 12																																		
ESF 21																	■	■	■	■	■													
ST 11					■	■	■	■	■	■																								
J5236																																		
J5232																																		
J5228																																		
ST 21																	■	■	■	■	■													
J5212																																		
J5208																																		
J5204																																		
BUSS 11HD																																		
BUSS 12HE																																		
BUSS 13AD																																		
BUSS 14AE													■	■	■																			
Baxter Wilson																																		
J5224																																		
J5220																																		
J5216																																		
Franklin																																		
J5240																																		
J5244																																		
J5248																																		
Switchyard Activities					■	■	■	■	■	■							■	■	■	■	■													
RFO9 Start: 4/11/98	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Outage Day	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34

DECAY HEAT REMOVAL KEY SAFETY FUNCTION

RFO9: 4/11/98	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	1	2	3	4	5	6	7	8	9	10	11	12	13	14
RHR Pump A						SS	SS																											
SSW A																																		
Division I D/G																																		
Buss 15AA																																		
RHR Pump B																						SS												
SSW B																																		
Division II D/G																																		
Buss 16AB																																		
SRVs																																		
ADHRS				T/C																					T/C									
Buss 14AE																																		
PSW																																		
Buss 18 AG																																		
Buss 28AG																																		
Div. I SDC: E12-F009																																		
Div. 2 SDC: E12-F008																																		
MSL Plugs Installed																																		
RWCU																																		
CCW																																		
Active SDC System		ADHR			ADHR - SFP SUCT								RHR B																HYDRO		RHR B			
Recirc Pump 'A'																																		
Recirc Pump 'B'																																		
LPCS																																		
LPCI A																																		
LPCI B																																		
LPCI C																																		
HPCS																																		
HPCS D/G																																		
Firewater																																		
Fuel Pool Cooling																																		
Sup. Pool Cooling																																		
Mode 5																																		
Mode 4																																		
ESF 11																																		
ESF 12																																		
ESF 21																																		
ST11																																		
ST21																																		
Franklin Line																																		
Baxter Wilson																																		
Sec. Containment					Secondary Containment Set (SCS)																												SCS	
Upper Pool Drained				Upper Pool Flooded (UPF)																											UPF			
Sup. Pool Lvl < 12' 8"																																		
RFO9: 4/11/98	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Outage Day	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34

ATTACHMENT 1 TABLE 5 UFSAR Events Key Safety Function Comparison

RFO9 Start: 4/11/98	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Outage Day	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34
KSF Risk	1	1	1	1	2	2	3	3	3	3	1						2	2	2	2	2				1	1	1	1	1	1				
SBO	1	1	1																						1	1	1	1						
LOCA																																		
Fire																	1	1	1	1														
TOTALS	2	2	2	1	2	2	3	3	3	3	1	0	0	0	0	0	3	3	3	3	2	0	0	0	2	2	2	2	1	1	0	0	0	0
RFO9 Start: 4/11/98	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Outage Day	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34

Attachment 6

GRAND GULF NUCLEAR STATION

SHUTDOWN OPERATIONS PROTECTION PLAN

REVISION 2
04/1/98

REVIEWED BY: ______________________ **Date:** 4-2-98
Outage Supt.

REVIEWED BY: ______________________ **Date:** 4-2-98
Operations Supt.

REVIEWED BY: ______________________ **Date:** 4-6-98
OM&WC Manager

REVIEWED BY: ______________________ **Date:** 4-6-9[illegible]
for **Operations Manager**

REVIEWED BY: ______________________ **Date:** 4-7-98
PSRC

Table of Contents

I. Introduction

Shutdown operations present the plant with a set of unique risks. Proper management of outage activities can reduce both the likelihood and consequences of shutdown events. The Grand Gulf Nuclear Station Shutdown Operations Protection Plan (SOPP) provides a set of specific outage equipment requirements/guidelines for maintaining nuclear safety during shutdown operations.

The Protection Plan guidelines are based on the "**Defense in Depth**" outage management philosophy and are contained in Section II of this document. Section III is a list of common terms and definitions as they apply to shutdown protection. Section IV provides general outage risk management quidelines. Section V gives a set of minimum equipment requirements for the specific Reactor shutdown conditions. Section VI is a list of contingency plans. Section VII is a list of references used in the preparation of this document. Time-to-Boil curves for various initial water level configurations can be found in Attachment #2.

The SOPP assumes the plant is in Mode 4 (Cold Shutdown) or Mode 5 (Refuel) or in the defueled condition. "Requirements" or "Required," as used in this document, is intended to mean available. Additional equipment "OPERABILITY" requirements are contained in Plant Technical Specifications and are assured of being met by use of the unit Operating Procedures.

The guidelines and minimum equipment requirements contained in this document provide guidance for scheduled, forced (unscheduled), and refueling outages. Attachment 1, Approval for Departure from the Requirements of Shutdown Operations Protection Plan, is used to document deviations from the requirements contained in Section IV. Deviations from quidelines containing a "should" or a "shall" require approval from the Outage Director or his designee. This approval does not allow deviations from the Plant Technical Specifications or TRM.

II. Outage Management Nuclear Safety Philosophy

Grand Gulf's safety philosophy for the conduct of shutdown operations is to integrate nuclear safety into the planning, scheduling and implementation of outage activities. The key attribute of this process is the "Defense-in-Depth" which includes: identification of shutdown risk as an element of the planning of outage activities, minimization of shutdown risk through the scheduling of activities, and providing systems, structures and components to provide backup for key safety functions through redundant, alternate or diverse methods. Successful safe and efficient implementation of outage activities depends on the dedication and teamwork among the outage team including contractors, and meticulous performance of outage activities as scheduled in the master outage schedule. The following principles are used to assure the successful management of outages at Grand Gulf.

- <u>OUTAGE MANAGEMENT STRATEGY</u>

  - Planned outages are conducted to perform corrective maintenance, preventative maintenance, required surveillance, and plant modifications to allow the plant to operate safely until it's next planned outage, and for the remainder of it's forty year operating license. Outage activities are selected consistent with this purpose to: reduce radiation exposure, improve personnel safety, improve plant operation, and meet regulatory requirements. Lists of approved activities are developed in advance to allow adequate time for design, procurement, and pre-installation activities. The Grand Gulf goal for outage durations is to conduct the shortest outage possible while accomplishing the outage scope with the highest level of both personnel and plant safety.

  - NUMARC 91-06, "Guidelines for Industry Actions to assess shutdown Management" is used to assess and improve outage safety by minimizing shutdown risk. The key element of this approach is the concept of "Defense-in-Depth".

  - "Defense in Depth" is the concept of ensuring that the systems and alternates that perform key safety functions are available when needed, particularly during high risk evolutions. The use of the High Impact Area methodology, coupled with an understanding of plant conditions and risk conditions, is an element to enhance minimizing shutdown risk.

- The recommendations contained in SOER 91-01 will be used to assure the safe conduct of Infrequently Performed Tests and Evolutions. These recommendations include the use of: pre-test briefings, clear and concise test procedures, and the establishment of criteria for terminating the test. At Grand Gulf, procedure 01-S-06-1 (Conduct Of Operations) Section 6.12 outlines these requirements.

- Conservative decision making should be used to guide the day to day management of Grand Gulf, including outages. Conservative decision making applies to outage planning functions such as selection of corrective maintenance and design changes as well as to the operational decisions to support outage activities. A high priority should be placed on equipment problems that require operator compensatory actions (workarounds). Equipment deficiencies should be periodically reviewed to assess the cumulative or aggregate effects of degraded equipment on operator ability to respond effectively to plant transients. Priorities for resolution should be adjusted if needed. Compensatory measures for special outage conditions should be clearly communicated to the Operating shift. The procedure and conditions requiring closure of the containment hatch are one example of a compensatory measure.

• <u>OUTAGE PLANNING</u>

- Outage planning is the process of selecting and reviewing outage activities to establish scheduling requirements based on the Plant Technical Specifications, operational, and implementation requirements and shutdown risk considerations.

- Outage planning must include a review of Infrequently Performed Tests and Evolutions to ensure adequate precautions are taken. Management oversight during test review and performance, pre-shift briefings, and the establishment of test termination criteria are some of the measures employed to ensure proper test conduct.

- ## OUTAGE SCHEDULING

  - Outage scheduling is the process of integrating outage activities into a coordinated schedule which efficiently and safely accomplishes the outage scope within the restraints identified through outage planning.

  - Key milestones are established to identify pre-outage activities, such as the scope freeze date, Design Change Package issue date, and work package issue date. These milestones will be established in advance to allow time for shutdown risk assessment, work implementation planning, and parts procurement and staging. It is the responsibility of all managers to identify all required outage scope prior to the applicable scope freeze milestone date.

  - Input for the detailed outage schedule is provided by past outage successes and a review of outage projects and scope, and the resources available. The schedule must take into account an assumed reserve of resources to deal with emergent issues. The reserve is based on past outage performance and management judgment of the potential for emergent work based on the planned outage activities. The detailed outage resource loading must consider the need for personnel to have a reasonable amount of time off.

  - The detailed outage schedule is developed to meet the Plant Technical Specifications, operational and implementation requirements in a manner that provides for "Defense-in-Depth" under all shutdown conditions. The minimum combination of safety equipment required to maintain critical safety functions is established for each phase of the outage. Projects representing special risk conditions will be scheduled during periods when the risk is minimized through a combination of plant conditions and equipment availability. Special emphasis will be given to the scheduling of work with the potential to adversely affect Shutdown Cooling, the availability of AC power sources, and periods when the combination of reactor inventory and decay heat load could result in a short time to boiling. An independent review of shutdown risk conditions and the final equipment providing critical safety functions is performed as part of the final schedule.

- <u>OUTAGE IMPLEMENTATION</u>

  - The outage organization will be structured to provide clear project responsibility and a clear reporting relationship for both pre-outage and outage activities. This organization and the project responsibilities will be communicated to all outage personnel. Outage management shift coverage will be structured to provide outage oversight and decision making capability available on site when necessary. Clear communications through the use of scheduled outage meetings and management tours of outage work areas are used to keep the outage team informed, and to emphasize the importance of safe and efficient outage conduct.

  - While the completion of outage activities generally reduces the shutdown risk, as the plant is returned to a normal operational alignment, the period just before plant restart presents a time of high activity with a heightened potential for personnel errors. Continued management shift coverage, equivalent to that employed during the major portion of the outage, should be considered during this period and the startup testing period. This enhanced coverage may be beneficial until the unit reaches a stable point in the post-outage power ascension.

- <u>OUTAGE CRITIQUE</u>

  - A comprehensive critique is used following each planned outage to provide a mechanism for continued improvement. The input for these critiques is structured to facilitate input from all levels of plant personnel. The critique items are tracked between outages and reviewed as part of the planning process for the next outage to ensure that corrective actions are taken. The critiques are shared between the plant sites to allow each plant to benefit from the lessons learned.

  - Outage risk minimization depends upon all departments carefully following the pre-approved outage schedule. Risk minimization is inherent in performing each task in the scheduled logic and in scheduled time period. For these considerations, emergent additions to outage scope shall be limited to those tasks which require an outage and which are necessary for safe and efficient operations in the succeeding fuel cycle.

III. Terms and Definitions

Available

The status of a system, structure or component that is in service or can be placed in service within a reasonably short period of time (consistent with its intended functional need). This condition recognizes that applicable Technical Specification requirements and/or licensing/design basis assumptions may not be maintained.

Adequate ECCS Inventory

Exists when there is sufficient volume of water to maintain Suppression Pool level above 11.5 ft. during steady state ECCS injection following a draindown or LOCA event to the Drywell. (see Risk Management Guidelines, Inventory Control Guidelines)

Containment Closure

A containment condition where a barrier to the release of radioactive material exists. For GGNS, this means primary containment exists for a boiling event leading to core damage.

Decay Heat Removal Capability

The ability to maintain reactor coolant system temperature and pressure and spent fuel pool temperature below specified limits following a shutdown.

Defense-in-Depth

For the purpose of managing risk during shutdown, "Defense-in-Depth" is the concept of:

- Providing systems, structures and components to ensure backup of key safety functions using redundant, alternate or diverse methods;

- Planning and scheduling outage activities in a manner that optimizes safety availability;
- Providing administrative controls that support and/or supplement the above elements.

Defueled

All fuel assemblies have been removed from the reactor vessel and placed in the Spent Fuel Pool and/or the Upper CTMT Pool.

Higher Risk Evolution

Outage activities, plant configurations or conditions where the plant is more susceptible to an event causing the loss of a key safety function.

Plant Key Safety Function Equipment & Systems

Equipment that is being relied upon to ensure a Key Safety Function is maintained available. This equipment is designated by a shutdown condition checksheet. This equipment is identified locally by signs on the door leading onto the protected equipment warning plant personnel to contact the Operations Plant Supervisor prior to entry.

Inventory Control

Measures established to ensure that irradiated fuel assemblies remain covered with coolant to maintain heat transfer and shielding requirements.

Key Safety Functions

During shutdown operations, the key safety functions are decay heat removal capability, inventory control, electrical power availability, reactivity control and containment.

Operable

The ability of a system to perform its specified function with all applicable Technical Specification requirements satisfied.

Reactivity Control

Procedures and processes used to prevent inadvertent criticalities, power excursions and loss of shutdown margin. These include methods to predict and monitor reactor core behavior.

Readily Established

For Primary and Secondary containment means that all tracking LCO's for inop valves are written and being tracked. For Primary containment this also means that procedures, work documents, equipment and personnel required to establish primary containment are prepared and available.

Safety Significant Change

Any change to the outage schedule that has a meaningful or notable impact on the required equipment, systems, or flowpaths.

Examples include:

1. The condition and/or equipment established specifically for a High Risk Evolution change.

2. The systems listed in the Hammock section of the integrated schedule that are used to meet or exceed the Technical Specifications change.

3. Any unplanned degradation of an ESF function required to be Operable in Modes 3, 4, or 5.

4. An off-normal or unscheduled change to the water movement plan that affects suppression pool level, reactor vessel level or reactor cavity level.

5. Rescheduling an AC or DC bus outage that affects ESF systems.

6. If in the determination of the Outage Director, a Shutdown Operations Protection Plan, Outage Risk Management Guideline (section IV) cannot be met.

Shutdown Conditions

For the purpose of establishing "Defense-in-Depth" requirements, an outage is divided into four possible configurations. These configurations are referred to as Shutdown Conditions. The Shutdown Conditions are numbered from the least impact to plant safety to the most significant safety impact. The four Shutdown Conditions are defined below:

1. The reactor is in Mode 4.

2. The reactor is in Mode 5 with cavity level low or flooded with the Gates installed.

3. The reactor is in Mode 5 with cavity flooded and gates not installed.

4. The reactor is defueled.

Shutdown Safety Level

GREEN: Considered minimal risk configuration. All minimum equipment requirements are satisfied. Generally, this condition will signify a TS+1 condition for Tech Spec related safety equipment.

YELLOW: Considered an acceptable risk. Increased awareness for the safety function is all that should be required for these conditions. Generally, this condition signifies a Tech Spec minimum requirement for safety related equipment.

ORANGE: Considered high risk. Written and pre-planned guidance/contingency plans should be made before entering a pre-planned condition of this type. These may be as complex as temporary systems or structures with associated written procedures, or as simple as a note in the War Room turnover sheets and the Operations night orders.

RED: Considered an unacceptable risk for a planned evolution or a probable Plant Technical Specification violation. Changes should be made to the schedule or equipment availability to further ensure maintainability of safety functions.

V. Outage Risk Management Guidelines

A. General

1. Planning

a. The outage schedule should be developed through interaction with involved organizations and disciplines to assure that the planning provides "Defense-in-Depth" throughout the outage. Activities in the outage schedule should be sufficiently detailed and organized to accurately convey the impact on complex evolutions, plant conditions, and equipment availability.

b. The outage work scope and schedule should realistically match resources to activities. Additional resources should be available to meet anticipated changes, such as increases to the outage scope.

c. Surveillance testing and preventative maintenance activities associated with key shutdown operations protection equipment or systems should be incorporated into the detailed outage schedule.

d. A detailed safety review of the outage schedule shall be performed by personnel knowledgeable in management expectations for outage nuclear safety and plant operations for all planned outages. The review should not be conducted solely by those directly involved in preparation of the outage schedule. A review shall be performed prior to the outage and prior to any safety significant changes to the outage schedule after the initial review. Major outage activities shall be controlled and implemented in accordance with the approved schedule.

e. Outage planning and execution should consider potential introduction of hazards (e.g., fire, flooding, etc.) posed by the level and/or scope of activities in a given area of the plant and establish compensatory measures as appropriate.

2. Training

a. Operator training should be performed on the shutdown safety issues described herein. To the extent practicable, simulator training for shutdown conditions should be performed.

b. Plant personnel, including contractors and others temporarily assigned to support the outage, should be trained in areas that are applicable to their particular role in outage activities and that contribute to the safe conduct of the outage.

c. Personnel who may be required to implement a contingency plan should be familiar with the plan.

3. Implementation

a. War Room personnel should verify the availability of the minimum required equipment for the current Shutdown Condition once per 12 hours and prior to entering any new Shutdown Condition. The check sheets will then be reviewed with the oncoming Shift Superintendent prior to his shift turnover. Section IV of this document contains those minimum equipment requirements.

b. The current plant status, including the availability of Key Safety Function systems or equipment, should be communicated on a regular basis to personnel who may affect plant safety. Higher risk evolutions should be conveyed including any appropriate precautions or compensatory actions during these periods.

c. Areas around protected Key Safety Function Equipment and their power supplies should be controlled by physical barriers with "High Impact Area," signs near or at the entrance to the operable equipment areas. Special precautions should be taken and pre-job briefings should be conducted for activities taking place within these controlled areas.

d. Key Safety Function Equipment that is removed from service for maintenance or testing should be returned to service as soon as the maintenance or testing is completed. When the equipment is returned to service, its availability should be assured by post maintenance testing, monitoring of key parameters, verification of alignment and/or administrative control by Operations, as appropriate.

e. The Outage Director has the responsibility to monitor scheduled activities with respect to the initial schedule sequence and approve any significant variations. Any changes will follow the guidelines contained in Section IV of this document. Any changes that deviate from these guidelines require completion of Attachment 1, Approval for Departure from the Requirements of the Shutdown Operations Protection Plan.

4. Post Outage

   a. A post-outage critique should be conducted that assesses outage performance from a safety perspective. The results of the critique should be used as a basis for improvements to planning and control of future outages.

B. Shutdown Cooling Guidelines

1. Guidelines

   a. The Emergency Diesel Generator associated with the operable Residual Heat Removal System shall remain operable.

   b. When credit is taken for an alternate means of decay heat removal (e.g., ADHR, RWCU, Natural Circ, etc.), one RHR system shall be available as a backup.

   c. The outage will be structured such that no work will be performed on the operable RHR system. (Except snubber inspections and testing).

   d. The RHR systems should be recovered to an Operable status as soon as possible following modifications or maintenance.

C. Inventory Control Guidelines

   a. The Emergency Diesel Generator associated with the operable ECCS shall remain operable.

   b. Emergency Core Cooling systems should be returned to an operable status as soon as possible following system maintenance or modifications.

   c. Activities on the Emergency Core Cooling systems should be scheduled in detail.

   d. Work activities will not be allowed on the operable Emergency Core Cooling systems. (Except snubber inspections and testing)

e. Adequate ECCS Inventory exists when there is sufficient volume of water available for ECCS injection to maintain at least 11.5 feet in the suppression pool plus have 49,261 ft^3 of water available to compensate for the drawdown volume in the event of a LOCA in modes 4 or 5.

Adequate ECCS Inventory exists when suppression pool level is ≥ 13.5 ft AND plant is in Mode 5, vessel head, separator and dryer removed, cavity flooded, and reactor cavity and separator pool weir gates installed.

Adequate ECCS Inventory exists when suppression pool level is ≥ 13.3 ft and the normal volume of water from the upper containment pool is available via SPMU.

If the reactor cavity has been drained, then Adequate ECCS Inventory exists whenever any of the following conditions exist:

1) The suppression pool level is ≥ 18.34 ft.
2) The suppression pool level is ≥ 16.60 ft
   AND the Separator Pool[1] water is available via SPMU.
3) The suppression pool level is ≥ 15.20 ft
   AND HPCS is available;
   AND CST level is ≥ 18 ft.
4) The suppression pool level is 13.50 ft
   AND the Separator Pool[1] water is available via SPMU;
   AND HPCS is available;
   AND CST level is ≥ 18 ft.

[1] Separator Pool level elevation 202 ft with or without the separator in the pool.

D. Electrical Power Distribution

1. Guidelines

a. Two offsite sources of power will be maintained available at all times during the shutdown period.

b. The Emergency Diesel Generator associated with the operable ECCS and Residual Heat Removal System shall remain operable.

c. Activities scheduled during an ESF division outage window should be directed away from the other operable ESF division.

d. Offsite power sources should be clearly identified on the refueling outage schedule.

e. Refueling outages will be divisional. This means the major work of an outage will be concentrated on one division only. 15AA ESF buss will be de-energized for maintenance during a Div I outage and 16AB ESF bus de-energized during a Div II outage.

f. A coordinator should be assigned to specifically plan the divisional bus outages and help identify temporary power requirements.

E. Reactivity Control

1. Guidelines

a. To ensure adequate neutron instrument monitoring (e.g. coupling) at least two fuel bundles should be maintained around each required operable detector string. For the purpose of criticality monitoring only the Source Range Monitors are required to be coupled.

b. Detailed shutdown margin assessments should be obtained to ensure adequate shutdown exists, assuming control rod withdrawal errors, fuel load errors and mis-orientation errors.

c. If the core has been completely offloaded, rod movement should not be allowed in a cell loaded with fuel once core loading has commenced, until after core verification.

d. Once fuel shuffling (one or more new fuel bundles or one or more old fuel bundles relocated within the core) has begun, rod movement should not be allowed in a cell loaded with fuel until core verification has been completed.

F. Containment Closure

1. Guidelines

a. Operations will maintain a list of all breaches to Primary and Secondary Containment.

b. The Mechanical Supervisors are assigned responsibility for the closure of the 166' containment equipment hatch, the 119' airlock and the 208' airlock should action be initiated by the Shift Superintendent or Outage Director.

c. Primary containment is assumed to NOT be available during Modes 4 and 5 and therefore increased awareness is required during OPDRV's, Core Alts and handling irradiated fuel.

G. Fuel Pool Cooling

1. Guidelines

a. Work on the Fuel Pool Cooling System should be done non-outage if possible. If work is required on this system during the outage, it should be done as early as possible in the outage and not after spent fuel from the reactor is transferred to the Spent Fuel Pool when the heat load will be higher. If work is required after the spent bundles are transferred to the SFP, a contingency plan should be in place prior to removing the system from service.

H. Fire

1. Guidelines

a. The Fire Protection System should be operable per Technical Specifications.

b. Work on the P64 Fire Protection system should be done non-outage if possible. This is to allow the P64 system to remain operable to provide an alternate emergency water source for RPV level control and decay heat removal.

c. Fire brigade requirements of Technical Requirement Manual should be met.

d. All personnel, including contractors, are trained in the proper fire notification procedures.

2. Risk Associated with a Fire in the Main Control Room.

    a. A fire is a risk when the Div I equipment is OOS. This is because Division I is the protected division for a fire in the main control room. The risk condition only applies to a fire in the main control room.

    b. With Division I equipment out of service, a fire in the Division II equipment could remove the ability to operate equipment from the Remote Shutdown Panel.

V. Equipment Requirements by S/D Condition

This section lists the minimum required equipment within each safety function for each Shutdown Condition. There are four Shutdown Condition Tables corresponding to the four identified Shutdown Conditions within the Grand Gulf ORAM model. The tables give equipment requirements by Safety Function. The requirements given are those necessary to yield a GREEN color, ie- lowest risk within the Safety Function. A GREEN condition of an analyzed Safety Function is generally achieved by having the required number of Tech Spec equipment plus one more. This is known as Tech Spec + 1 or TS+1. There are, however, some Safety Functions within some Shutdown Conditions in which the lowest risk attainable is YELLOW. These are noted in the attached tables. Also, the presence of a Higher Risk Evolution (HRE) activity will result in a non-GREEN color even if all the requirements for that Safety Function are satisfied. For instance, an activity that has a potential for a loss of decay heat removal will be YELLOW during it's scheduled time span even if TS+1 exists.

The Shutdown Conditions identified in this section are based on three Reactor variables:

a. Location of the fuel (any in the reactor vessel or all in the spent fuel pool).
b. Reactor Pressure Vessel head is off or installed. (Mode 4 or 5)
c. The amount of inventory in the Reactor Coolant System.

Condition 1 - The reactor is in Mode 4.

Condition 2 - The reactor is in Mode 5 with cavity level low or flooded with the Gates installed.

Condition 3 - The reactor is in Mode 5 with cavity flooded and gates not installed.

Condition 4 - The reactor is defueled.

SHUTDOWN CONDITION 1

MODE: 4 **STATE:** Cold S/D **FUEL STATUS:** Fueled
RPV LEVEL: Any **POOL GATES:** N/A

DECAY HEAT REMOVAL (SDC)

Circle appropriate color

[ ] 1. Of the following three available for decay heat removal.
( ) RHR A
( ) RHR B
( ) ADHR

-OR-

[ ] 2. RWCU if in Ops Hydro

Green - Three available Yellow- Two available Orange- One available Red - Zero available

T.S. Requires 2 RHR SDC systems operable.

Comment/Contingency: ______________________________

FUEL POOL COOLING (FPC)

[ ] 1. Sufficient Fuel Pool Cooling Trains available for current heat load.

Green - Available FPC Trains are sufficient Yellow- RHR in FPC assist Red - nothing avail

T.R.M. Requires maintaining pool temp <140F.

Comment/Contingency: ______________________________

SHUTDOWN CONDITION 1 (cont.)

Circle appropriate color

AC POWER CONTROL (AC)

[ ] 1. Of the following three offsite power sources:
- ( ) a. Baxter Wilson
- ( ) b. Franklin
- ( ) c. Port Gibson

-AND-

[ ] 2. Of the following three ESF transformers:
- ( ) a. ESF11/ST11
- ( ) b. ESF21/ST21
- ( ) c. ESF12

-AND-

[ ] 3. Emergency Diesel Generators
- ( ) a. Div I
- ( ) b. Div II

```
For offsite power sources
and ESF xfmrs:

Green  - >= Two available
Yellow - One available
Red    - Zero available
```

```
For Div 1 & 2 D/G's:

Green  - Two available
Yellow - One available
Red    - Zero available
```

T.S. Requires 1 offsite feeder and Div 1 or Div 2 EDG.

Comment/Contingency: ______________________________

INVENTORY CONTROL (IC)

[ ] 1. Adequate ECCS Inventory exists and of the following five systems:
- ( ) a. RHR LPCI A
- ( ) b. RHR LPCI B
- ( ) c. RHR LPCI C
- ( ) d. LPCS
- ( ) e. HPCS

```
Green  - >=Three available
Yellow- Two available
Orange- One available OR
   less than adequate
   ECCS inventory exists.
Red    - Zero available
```

T.S. Requires 2 systems operable AND SP level >12'8" OR, for HPCS only CST level >18'.

Comment/Contingency: ______________________________

SHUTDOWN CONDITION 1 (cont.)

Circle appropriate color

CONTAINMENT CONTROL (CON)

[ ] 1. Of the following if not handling irradiated fuel, core alts or performing OPDRV's:

( ) Secondary Containment operable and and SBGT A and SBGT B operable.

[ ] 2. Of the following if handling irradiated fuel, core alts or performing OPDRV's:

( ) a. Secondary CTMT Operable
( ) b. SBGT A operable
( ) c. SBGT B operable

T.S. Requires Sec CTMT and A&B SBGT if handling irradiated fuel or performing OPDRV's.

Not handling irr. fuel, core alts or not performing OPDRVS:

Green - All three operable.
Yellow- < All operable.

Handling irr. fuel, core alts or performing OPDRVS:

Yellow- Sec CTMT operable and two SBGT trains operable.
Orange- Sec CTMT operable and one SBGT train operable.
Red - Sec CTMT not operable or two SBGT trains not operable.

Comment/Contingency: ____________________

REACTIVITY CONTROL (RC)

[ ] 1. All control rods fully inserted or one rod out interlock is operable.

T.S. Shutdown Margin must always be met. Control Rods fully inserted during fuel loading. Control rods may be withdrawn under T.S. 3.10

Green - All Inserted

Yellow- Not all inserted AND one rod out interlock operable AND TS 3.10 for single rod removal met.

Red - SDM not met or not all inserted AND one rod out interlock not operable OR TS 3.10 for single rod removal not met.

Comment/Contingency: ____________________

Performed By:____________________**Date/Time:**____________________

SHUTDOWN CONDITION 2

MODE: 5 **STATE:** Refuel **FUEL STATUS:** Fueled
RPV LEVEL: Not Flooded OR Flooded **POOL GATES:** Installed

DECAY HEAT REMOVAL (SDC)

Circle appropriate color

[ ] 1. Of the following three available for SDC.

( ) RHR A
( ) RHR B
( ) ADHR

Green - Three available Yellow- Two available Orange- One available Red - Zero available

T.S. Requires 2 RHR systems operable if not flooded. This does not depend on pool gates installed or not installed.

Comment/Contingency: ____________________

FUEL POOL COOLING (FPC)

[ ] 1. Sufficient Fuel Pool Cooling Trains available for current heat load.

Green - Available FPC Trains are sufficient Yellow- RHR in FPC assist Red - nothing avail

T.R.M. Requires maintaining pool temp <140F.

Comment/Contingency: ____________________

SHUTDOWN CONDITION 2 (cont.)

Circle appropriate color

INVENTORY CONTROL (IC)

[ ] 1.Adequate ECCS Inventory exists and three out of the following five items:

( ) a. RHR LPCI A
( ) b. RHR LPCI B
( ) c. RHR LPCI C
( ) d. Low Pressure Core Spray
( ) e. High Pressure Core Spray

```
Green  - >=Three available
Yellow- Two available
Orange- One available OR
   less than adequate ECCS
   inventory exists.
Red    - Zero available
```

T.S. Requires 2 ECCS systems operable AND SP level > 12'8" OR, for HPCS only-CST level >18ft

Comment/Contingency: ______________________________

____

____

____

AC POWER CONTROL (AC)

[ ] 1. Of the following three offsite power sources:
( ) a. Baxter Wilson
( ) b. Franklin
( ) c. Port Gibson

-AND-

[ ] 2. Of the following three ESF transformers:
( ) a. ESF11/ST11
( ) b. ESF21/ST21
( ) c. ESF 12

-AND-

[ ] 3. Emergency Diesel Generators
( ) a. Div I
( ) b. Div II

```
For offsite power sources
and ESF xfmrs:

Green  - >= Two avail.
Yellow - One available
Red    - Zero available
```

```
For Div 1 and 2 D/G's:

Green  - Two available
Yellow - One available
Red    - Zero available
```

T.S. Requires 1 offsite feeder and Div 1 or Div 2 EDG

Comment/Contingency: ______________________________

____

____

____

SHUTDOWN CONDITION 2 (cont.)

Circle appropriate color

CONTAINMENT CONTROL (CON)

[ ] 1. Of the following if not handling irradiated fuel, core alts or performing OPDRV's:

( ) Secondary Containment operable and and SBGT A and SBGT B operable.

[ ] 2. Of the following operable if handling irradiated fuel, core alts or performing OPDRV's:

( ) a. Secondary CTMT Operable
( ) b. SBGT A operable or running
( ) c. SBGT B operable or running

T.S. Requires Secondary CTMT and A&B SBGT if handling irradiated fuel, performing core alts or performing OPDRV's.

Not handling irr. fuel, core alts or not performing OPDRVS:

Green - All three operable.
Yellow- < All operable.

Handling irr. fuel, core alts or performing OPDRVS:

Yellow- Sec CTMT operable and two SBGT trains operable.
Orange- Sec CTMT operable and one SBGT train running.
Red - Sec CTMT not operable or two SBGT trains not operable or running.

Comment/Contingency: ______________________________

REACTIVITY CONTROL (RC)

[ ] 1. All control rods in fueled cells are fully inserted or one rod out interlock is operable.

T.S. Shutdown Margin must always be met. All Control Rods fully inserted during fuel loading. Control rods may be withdrawn under T.S. 3.10.4

Green - All Inserted

Yellow- Not all inserted AND one rod out interlock operable AND TS 3.10.5 for single rod removal met.

Red - SDM not met or not all inserted AND one rod out interlock not operable OR TS 3.10 for single rod removal not met.

Comment/Contingency: ______________________________

Performed By:______________________ **Date/Time:**______________

SHUTDOWN CONDITION 3

MODE: 5 **STATE:** Refuel **FUEL STATUS:** Fueled
RPV LEVEL: Flooded **POOL GATES:** Not installed

SHUTDOWN COOLING (SDC)

Circle appropriate color

A. Not within natural circulation heat removal capacity.
[ ] 1. Two of the following three available for SDC.
( ) RHR A
( ) RHR B
( ) ADHR

See attached logic diagram SDC-3 for color assignments.

T.S. Requires 1 RHR system operable and one decay heat removal sys in service.

B. Within natural circulation heat removal capacity.
[ ] 1. Two of the following four available for SDC.
( ) RHR A
( ) RHR B
( ) ADHR
( ) Natural Circulation and two loops FPCCU trains plus RWCU (RWCU not req after 22 days after shutdown.

See attached logic diagram SDC-3 for color assignments.

T.S. Requires 2 ECCS systems operable and one decay heat removal sys in service.

Comment/Contingency:

FUEL POOL COOLING (FPC)

[ ] 1. Sufficient Fuel Pool Cooling Trains available for current heat load.

Green - Available FPC Trains are sufficient
Yellow- RHR in FPC assist
Red - nothing availible

T.R.M. Requires maintaining pool temp <140F.

Comment/Contingency:

SHUTDOWN CONDITION 3 (cont.)

Circle appropriate color

INVENTORY CONTROL (IC)

[ ] 1. Adequate ECCS Inventory exists and of the following five systems:

( ) a. RHR LPCI A
( ) b. RHR LPCI B
( ) c. RHR LPCI C
( ) d. LPCS
( ) e. HPCS

```
Green - >= 1 available
Yellow- 0 available
Orange- <than adequate
        ECCS inventory.
```

T.S. No ECCS required with cavity flooded and gates removed

Comment/Contingency: ______________________________

AC POWER CONTROL (AC)

[ ] 1. Of the following three offsite power sources:

( ) a. Baxter Wilson
( ) b. Franklin
( ) c. Port Gibson

-AND-

[ ] 2. Of the following three ESF transformers:

( ) a. ESF11/ST11
( ) b. ESF21/ST21
( ) c. ESF12

-AND-

[ ] 3. Emergency Diesel Generators

( ) a. Div I
( ) b. Div II

```
For offsite power sources
and ESF xfmrs:

Green  - >= Two available
Yellow - One available
Red    - Zero available
```

```
For Div 1 and 2 D/G's:

Green  - Two available
Yellow - One available
Red    - Zero available
```

T.S. Requires 1 offsite feeder and Div 1 or Div 2 EDG.

Comment/Contingency: ______________________________

SHUTDOWN CONDITION 3 (cont.)

Circle appropriate color

CONTAINMENT CONTROL (CON)

[ ] 1. Of the following if not handling irradiated fuel, core alts or performing OPDRV's:

( ) Secondary Containment operable and and SBGT A and SBGT B operable.

[ ] 2. Of the following operable if handling irradiated fuel, core alts or performing OPDRV's:

( ) a. Secondary CTMT Operable
( ) b. SBGT A operable
( ) c. SBGT B operable

T.S. Requires Secondary CTMT and A&B SBGT if handling irradiated fuel, performing core alts or performing OPDRV's.

```
Not handling irr. fuel,
core alts or not performing
OPDRVS:

Green - All three
  operable.
Yellow- < All operable.
---------------------------
Handling irr. fuel, core
alts or performing OPDRVS:

Yellow- Sec CTMT operable
   and two SBGT trains
   operable.
Orange- Sec CTMT operable
   and one SBGT train
   operable.
Red - Sec CTMT not
   operable or two SBGT
   trains not operable.
```

Comment/Contingency: ______________________________

____

____

____

REACTIVITY CONTROL (RC)

[ ] 1. All control rods in fueled cells are fully inserted or one rod out interlock is operable.

T.S. Shutdown Margin must always be met. Control Rods fully inserted during fuel loading. Control rods maybe withdrawn under T.S. 3.10

```
Green - All Inserted

Yellow- Not all inserted
AND one rod out interlock
operable AND TS 3.10.X for
single rod removal met.

Red - SDM not met or not
all inserted AND one rod
out interlock not operable
OR TS 3.10.X for single rod
removal not met.
```

Comment/Contingency:

____

____

____

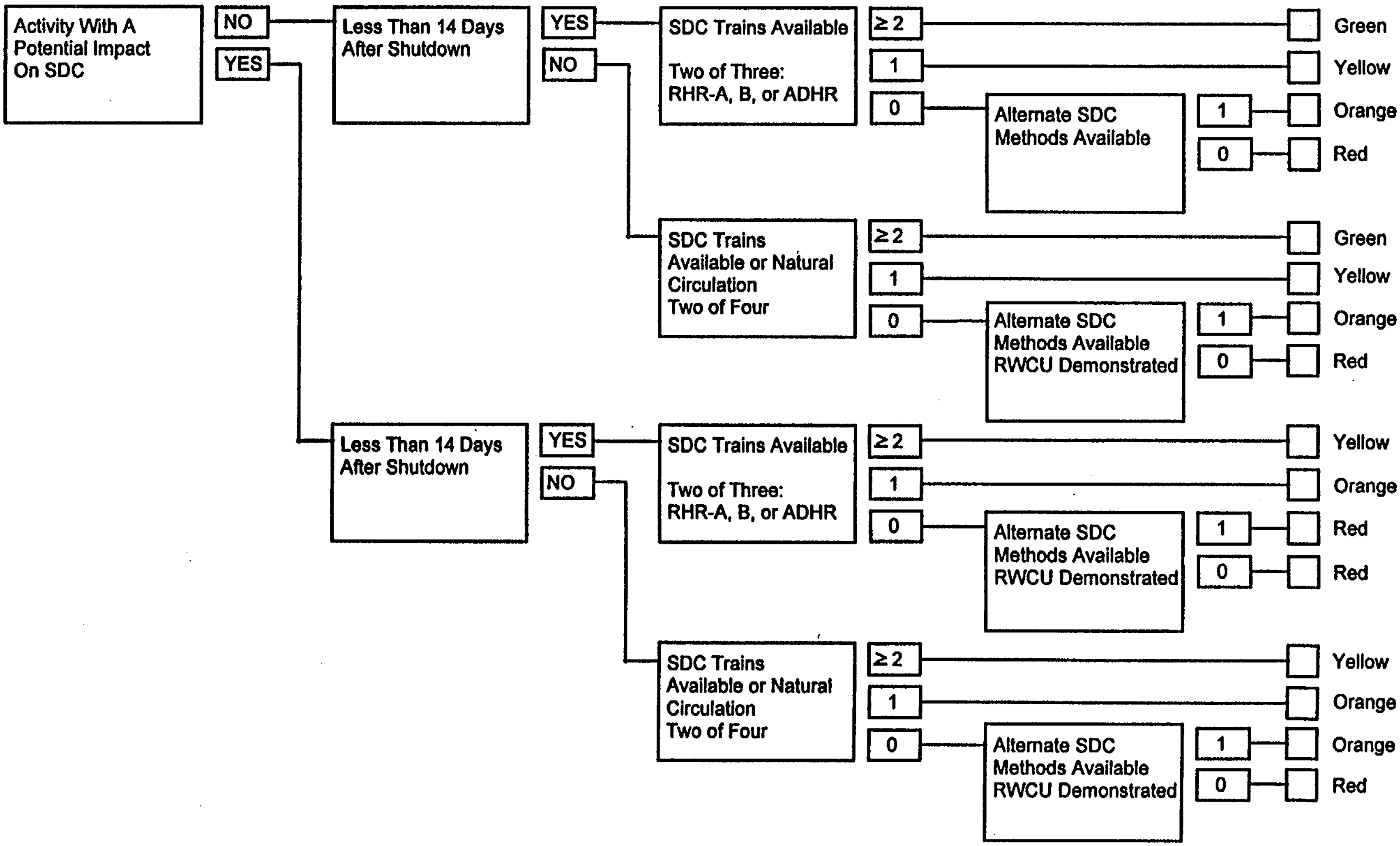
Performed By:______________________________ **Date/Time:**________________

RF0 Shutdown Operations Protection Plan

SHUTDOWN CONDITION 3

Logic SDC-3 Shut Down Cooling

Revision 1



SHUTDOWN CONDITION 4

MODE: N/A **STATE:** N/A **FUEL STATUS:** Defueled
RPV LEVEL: N/A **POOL GATES:** N/A

DECAY HEAT REMOVAL (SDC)

Circle appropriate color

NONE

T.S. None.

FUEL POOL COOLING (FPC)

A. High/Medium Decay Heat (<14 Days After Shutdown)
   [ ] 1. Two Fuel Pool Cooling Trains

B. Low Decay Heat (14 Days After Shutdown)
   [ ] 1. One Fuel Pool Cooling Train

See attached logic diagram FPC-4 for color assignments.

T.S. Maintaining pool temp <140 F.

Comment/Contingency:

AC POWER CONTROL (AC)

[ ] 1. Two Offsite Power Sources
   ( ) a. Baxter Wilson
   ( ) b. Franklin
   ( ) c. Port Gibson

-AND-

[ ] 2. Two Emergency Diesel Generators
   ( ) a. Div I D/G
   ( ) b. Div II D/G
   ( ) c. Div III D/G

For offsite power sources:

Green - Three available
Green - Two available
Yellow - One available
Red - Zero available

For Div 1 and 2 D/G's:

Green - Two available
Yellow - One available
Red - Zero available

T.S. Requires 1 offsite feeder and Div 1 or Div 2 EDG if moving irradiated fuel in the Primary or Secondary CTMT.

SHUTDOWN CONDITION 4 (cont)

Circle appropriate color

Comment/Contingency for AC POWER CONTROL (AC):

INVENTORY CONTROL (IC)

[ ] 1. One ECCS System Available

( ) a. RHR LPCI A
( ) b. RHR LPCI B
( ) c. RHR LPCI C
( ) d. LPCS
( ) e. HPCS

```
Green - >= 1 available
Yellow- 0 available
```

T.S.: No ECCS required if fuel is offloaded.

Comment/Contingency:

CONTAINMENT CONTROL (CON)

[ ]1. Secondary Containment established.

[ ]2. SBGT A & B operable or running.

```
Handling irr. fuel:

Green - Sec CTMT operable
   and two SBGT trains
   operable.
Orange- Sec CTMT operable
   and <two SBGT trains
   operable.
Orange- Sec CTMT not
   operable and two SBGT
   trains running.
Red    - Sec CTMT not
   operable and <2 SBGT
   trains running.
```

T.S.: Required if moving irradiated fuel in Primary or Secondary CTMT

Comment/Contingency:

SHUTDOWN CONDITION 4 (cont)

REACTIVITY CONTROL (RC)

NONE

T.S. SDM must be met. T.S. 3.10.4 allows rod movement.

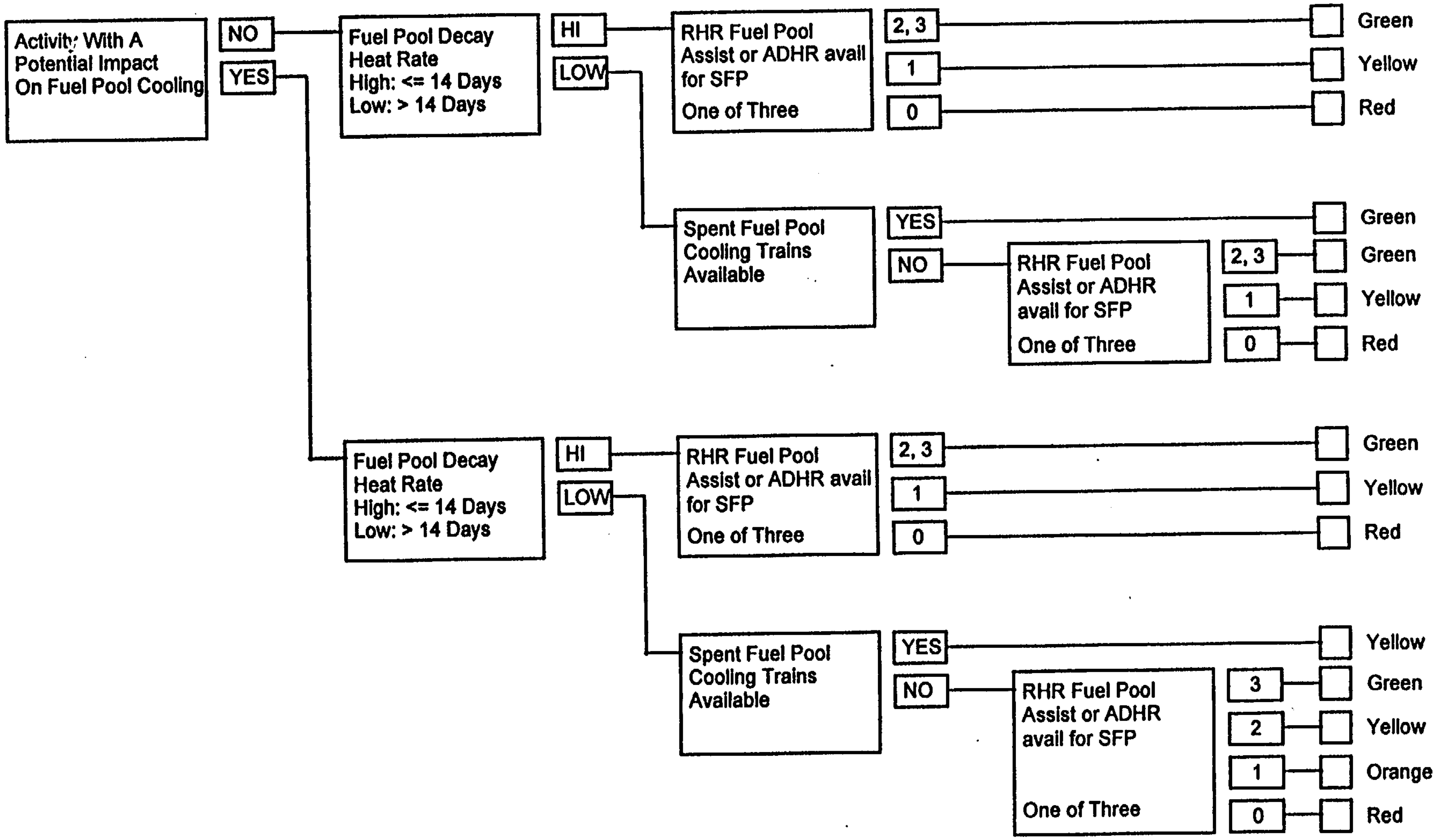
Performed By:______________________ **Date/Time:**______________

RF0 Shutdown Operations Protection Plan

SHUTDOWN CONDITION 4

Logic FPC-4 Fuel Pool Cooling

Revision 1



VI. Contingency Plans

Contingency Plans should be developed for situations where the system availability drops below the planned "Defense-in-Depth" and should be available when entering the higher risk evolution for which they were developed. The personnel required to implement the contingency plan should be identified and be familiar with the plan.

A. Decay Heat Removal

1. Reactor Coolant System Decay Heat Removal

Decay Heat Removal contingencies are covered in ONEP (Off Normal Event Procedure) 05-1-02-III-1 Inadequate Decay Heat Removal. This procedure references SOI 04-1-01-E12-1 Residual Heat Removal which contains guidance for shutdown cooling operations and the line up and start of Alternate Decay Heat Removal if the required shutdown cooling is not available. The operators will be aware at all times which systems are available to provide Reactor Coolant System Decay Heat Removal to meet Technical Specification Requirements.

2. Containment Pool Cooling

Containment Pool Cooling contingencies are covered in ONEP 05-1-02-III-1, Inadequate Decay Heat Removal. This procedure references SOI 04-1-01-G41-1, Fuel Pool Cooling and Cleanup System as the primary method for cooling. SOI 04-1-01-E12-1, Residual Heat Removal System operating procedure is also referenced as a backup method when operated in the Fuel Pool Cooling assist mode.

3. Spent Fuel Pool Cooling

Spent Fuel Pool Cooling contingencies are covered in ONEP 05-1-02-III-1, Inadequate Decay Heat Removal. This procedure also contains procedural guidance for providing SSW backup cooling to FPC heat exchangers in the event of a loss of Plant Service Water.

B. Reactor Coolant System Inventory Makeup

Reactor coolant system inventory contingencies are covered in different locations. ONEP 05-1-02-I-4, Loss of AC power provides instructions for recovery of power availability, as necessary. Guidance is provided by EP-2, RPV Control, which identifies emergency makeup sources.

C. Electrical Power Distribution

Electrical Power contingencies are provided in ONEP 05-1-02-I-4 Loss of AC Power. This includes guidelines for a station blackout. This procedure also provides instruction for energizing Division I or Division II from Division III if required to maintain adequate core cooling or to maintain the plant in a safe shutdown condition. Specific guidance for loss of electrical power to the FPC pumps are contained in SOI 04-1-01-G41-1.

D. Reactivity Control

Reactivity control is maintained during the refueling outage using the rules and guidelines contained in Operations section procedures, Reactor Engineering procedures 17-S-02-100 Criticality Rules and 17-S-02-300 SNM Movement and Inventory Control. In addition, reactor coolant temperature is monitored by the Control Room Tech Spec rounds sheets 06-OP-1000-D-0001 Att II (mode 4) and III (mode 5). Reactor Engineering is notified if temperature falls below 70 F.

E. Containment

Containment closure contingencies include Operations tracking inoperable penetrations with LCO's. The Operations Shift Superintendent will notify the Maintenance Department to take necessary actions to establish primary containment integrity should the need occur.

F. Fire

Communicate high risk evolutions at the shift turnover meetings. Do not allow potential fire hazards to occur in or around Div II equipment. Hang "High Risk Impact Area" signs as necessary. Additional contingency plans associated with administrative controls for protected equipment is contained in the referenced safety assessment report of the RFO9 schedule. (Ref: GIN 98/00519).

VII. Reference

01-S-06-42	Refueling Outage Organization
05-1-02-III-1	Inadequate Decay Heat Removal
05-1-02-I-4	Loss of AC Power
04-1-01-E12-1	Residual Heat Removal System
04-1-01-E12-1	Alternate Decay Heat Removal
04-1-01-G41-1	Fuel Pool Cooling and Cleanup System
EP-2	RPV Control
05-1-02-I-4	Loss of AC Power
17-S-02-100	Criticality Rules
17-S-02-300	SNM Movement and Inventory Control 06-OP-1000-D-0001 att II (mode 4) and III (mode 5) CNTL RM Tech Spec rounds sheets.
UFSAR	1.2.2.8.20
UFSAR	3.1.2.6.2
UFSAR	9.1.3.1.2
UFSAR	9.1.3.3
UFSAR Table	6.5-1a
UFSAR Table	6.5-3
ORAM	EPRI ORAM (Outage Risk Assessment & Management) integrated software version 1.5 DOS and 2.0 Windows
NUMARK 91-06	'Guidelines for Industry Actions to Assess Shutdown Management.'
INPO	INPO Outage Management Guidelines.
EPRI	NSAC 173 "Survey of BWR Plant Personnel on Shutdown Safety Practices and Risk Management Needs.'
EPRI	NSAC 175L "Safety Assessment of BWR Risk During Shutdown Operations."
EPRI	TR-102973 "Contingency Strategies for BWRs During Potential Shutdown Operation Events."
EPRI	TR-102971 "Generic Outage Risk Management Guidelines for BWRs."
GIN 95/01275	Memo from M. Withrow to T. Jablonski dated 4/11/95. Subject "Minimum Suppression Pool Level During RFO's."
GIN 98/00519	OA-98-01, Safety Assessment of the RFO9 refueling outage schedule.
ER 96/0621	RWCU heat removal performance/capabilities

ATTACHMENT 1

APPROVAL FOR THE DEPARTURE FROM THE REQUIREMENTS OF THE SHUTDOWN OPERATIONS PROTECTION PLAN

The intent of the Shutdown Operations Protection Plan is to document a set of specific guidelines and minimum equipment requirements by which to conduct outages and thereby maintain nuclear safety during shutdown operations. Approval for departure from requirements contained in the Shutdown Operations Protection Plan is obtained by filling out this attachment and obtaining the appropriate signatures. Deviations from guidelines containing a "should" and a "shall" require approval from the Outage Director. This approval does not allow the deviation from Technical Specifications.

1. Description of departure - what specific requirement will not be satisfied?

2. Why is this departure necessary?

3. Estimated duration departure will be in effect?

4. Will compensatory measures be taken? If not, why not? If so, what are they?

_______________________ / _______ _______________________ /

Originator Date Supervisor Review Date

_______________________ /

Approved By Outage Director

ATTACHMENT 2

THERMAL HYDRAULIC CURVE

The attached curves represent the time to boil and time to top of active fuel for various initial fuel pool water level configurations for a specific Grand Gulf Refuel Outage. Also attached is the fuel pool curve for time to reach 140.0 Fahrenheit based on the specific outage heat load.

The design temperature limits for containment and spent fuel pools are:

Spent fuel pool maximum design temperature is 140.0 F

ref: UFSAR section: 1.2.2.8.20
3.1.2.6.2
9.1.3.1.2
9.1.3.3

Containment maximum design temperature is 185.0 F

(ref: UFSAR table 6.2-1a and 6.5-3)

Date: March 2, 1998

To: W.C. Cade (G-ADM1-OPS)

From: M.D. Withrow, Manager, Safety Analysis

Subject: RFO9 Decay Heat Issues

Reference:
1. GIN 96/02207, M.D. Withrow to W.C. Cade, "RFO8 Decay Heat Issues", dated September 5, 1996.
2. Calculation XC-Q1J11-95002, Rev. 2, "Refueling Outage Decay Heat Issues".
3. CEO 98/00048, R.B. Lang to M.D. Withrow, "Grand Gulf RFO9 Decay Heat Analysis", dated February 16, 1998.

GIN: 98-00410

Attached are the time-to-boil and TAF curves for RFO9 for incorporation into plant procedures. These curves differ from those transmitted by Reference 1 in that the analysis now incorporates two different initial pool temperatures. Additionally, the fuel movement curves are no longer part of the current analysis. The analysis is documented in Reference 2 and incorporates the following assumptions:

- Initial water temperatures of 120 °F and 150 °F,
- No ambient heat losses, and
- Decay heat loads taken from Reference 3.

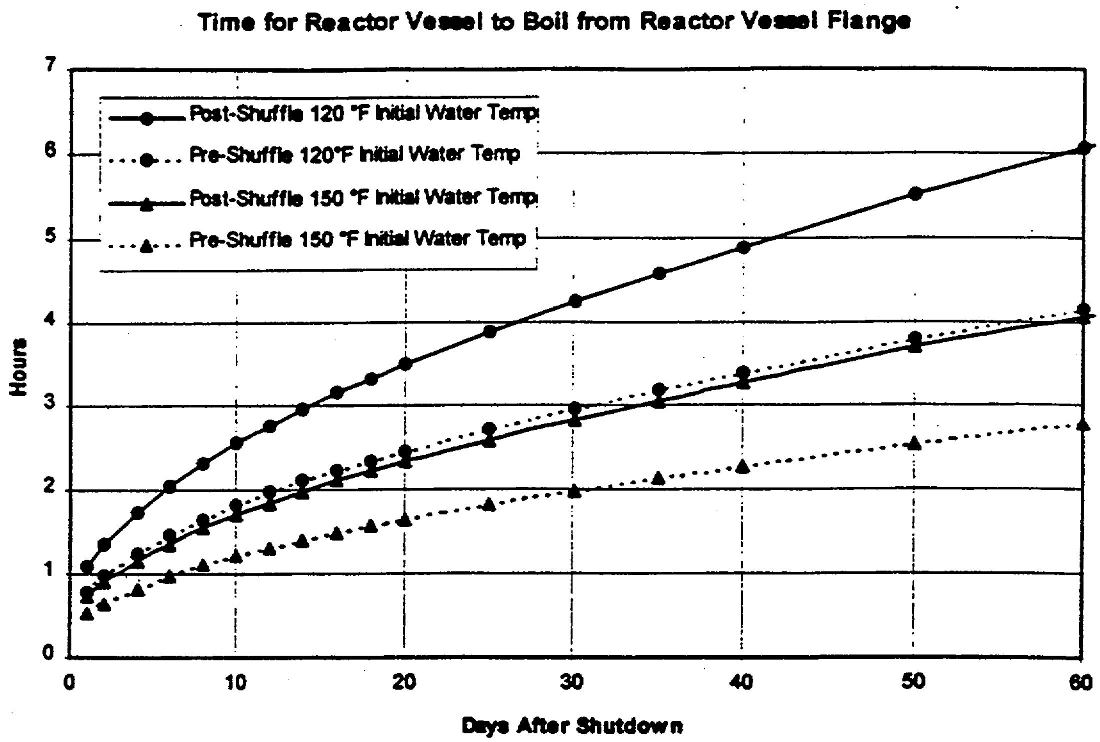
Any questions/comments on this matter can be directed to Scott Stanchfield (x6563) or Mike Withrow (x6247).

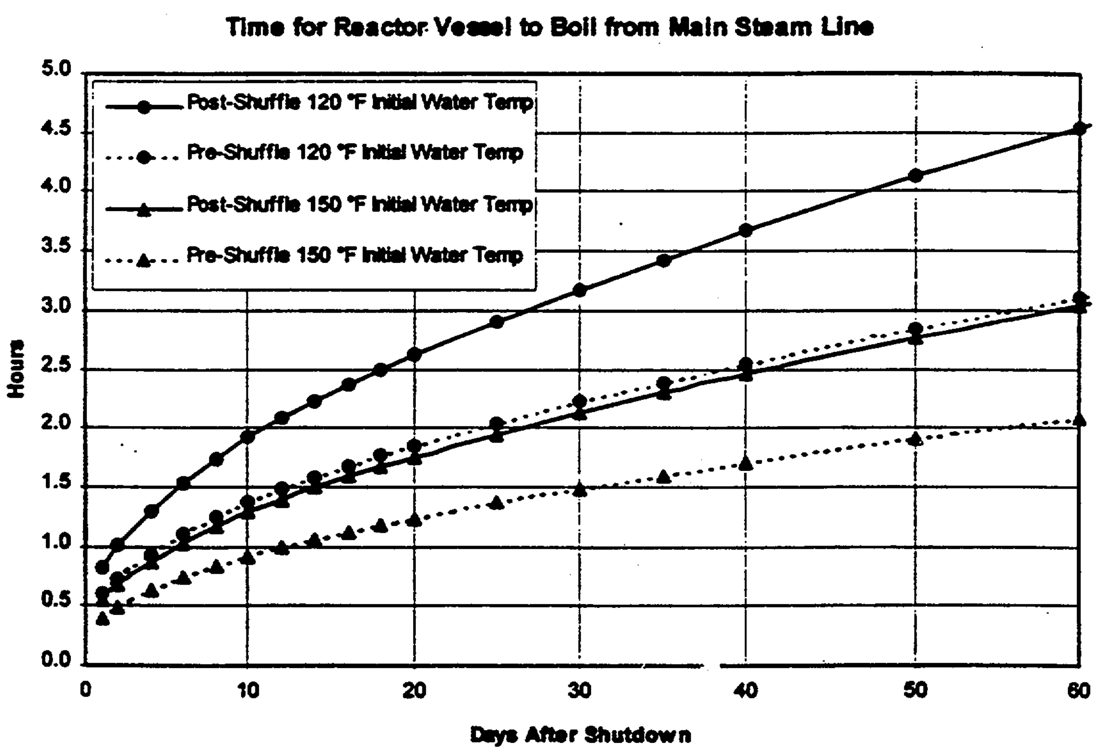
M. D. Withrow

Mike Withrow

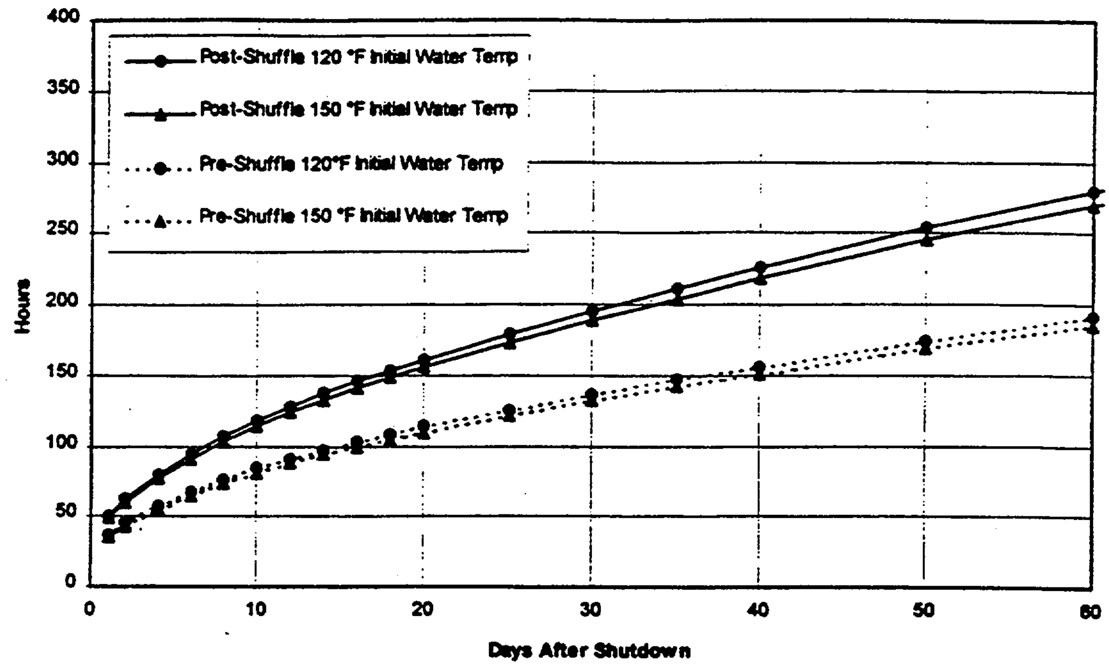
SCS/MDW
Attachment

cc: K.L. Walker (G-ADM2-PSE), w/a
George H. Lee (G-SSB2-NSA), w/a
NPE (GIN) File w/a
Central File ~~(6)~~ 5 Mc 3-5-98 w/a


Time for Reactor Vessel to Boil from Reactor Vessel Flange
Post-Shuffle 120 °F Initial Water Temp
Pre-Shuffle 120°F Initial Water Temp
Post-Shuffle 150 °F Initial Water Temp
Pre-Shuffle 150 °F Initial Water Temp
Hours
0
1
2
3
4
5
6
7
0
10
20
30
40
50
60
Days After Shutdown


Time for Reactor Vessel to Boil from Main Steam Line
Post-Shuffle 120 °F Initial Water Temp
Pre-Shuffle 120 °F Initial Water Temp
Post-Shuffle 150 °F Initial Water Temp
Pre-Shuffle 150 °F Initial Water Temp
Hours
0.0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
4.5
5.0
0
10
20
30
40
50
60
Days After Shutdown

Time to TAF from High Water Level



Time to TAF from Reactor Vessel Flange