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Enclosure

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EXECUTIVE SUMMARY

This preliminary assessment of Crystal River Unit 3 was conducted by the Special Inspection Branch of the U.S. Nuclear Regulatory Commission's Office of Nuclear Reactor Regulation during the weeks of June 3 and June 10, 1996. The purpose of the assessment was to develop an integrated perspective of performance strengths and weaknesses based upon an in-office review of inspection reports, event reports, and other NRC and licensee generated performance information. The assessment covered a two year period from June 1994 to June 1996. An on-site assessment scheduled to begin on July 8, 1996 will be conducted to validate the conclusions reached during this in-office review.

The team identified that the licensee's corrective action programs have generally been effective at identifying specific equipment, program, and personnel related issues; however, the communication of management standards, issue prioritization, and the overall integration and trending of performance data were weak. Consequently, the licensee has not demonstrated the ability to identify, assess, and resolve the broader programmatic and performance problems that have been identified by external organizations. Until recently, corrective actions have generally been directed at lower levels within the organization, while weaknesses in management systems were not given sufficient attention.

The effectiveness of licensee self assessments and quality audits has been mixed. The team noted untimely or ineffective resolution with issues such as those concerning repeated problems with high pressure injection line flow instrumentation; with proper manning of the site fire brigade; with numerous emergency operating procedure deficiencies; with inadequate revisions to a curve pertaining to maximum make-up tank over-pressure; and with inconsistencies between pump test acceptance criteria and the Final Safety Analysis Report for 24 pumps. Weaknesses were also identified with the resolution of issues such as those concerning the operability determination process; the control complex habitability envelope; root cause evaluations; and the existence of a large Request for Engineering backlog.

Safety focus was mixed in the area of operations. There were several examples of conservative operating decisions made by the operators. However, unauthorized tests conducted by operators on the make-up tank resulted in operation of the plant outside its design basis and indicated that management had apparently not set the proper standards with regard to plant operation. Prior to the unauthorized testing, operators had expressed concerns regarding the pressure curve for the make-up tank, but the licensee was unable to resolve the concerns until after the issue was highlighted by the conduct of the unauthorized testing. Problems with communications, both within the operations department, and with other groups on-site were noted. Also, weaknesses were noted with the licensee's operability determination process, and with adherence to technical specifications. Routine operator performance during power operations and during outage periods was adequate.

Problems were also noted with procedural adherence and with the adequacy of operational procedures. Many of the weaknesses documented were indicative of

management's failure to establish clear expectations regarding the conduct of tests, response to alarms/annunciators, and self-verification.

The engineering department has often demonstrated a weak safety perspective. Numerous examples were identified where a weak safety focus has resulted in operation of the plant outside of design or technical specification limits. Also, in some instances, the Licensing Department has provided non-conservative technical specification interpretations. A recent position taken by the licensee concerning the required availability of systems to prevent the precipitation of boron in the reactor core following design basis loss of coolant accidents appeared to be without adequate technical basis, and appeared to be contrary to both the original design basis of the plant and to previously stated regulatory positions.

Several good self assessment efforts have been performed within the engineering area; however, corrective actions to the identified findings have often been superficial. Likewise, weaknesses were identified with engineering response to issues identified by the site-wide corrective action programs.

Numerous examples have been identified where the quality of engineering work was inadequate, including examples pertaining to the make-up tank pressure curve, design modifications, and in licensing submittals to the NRC. Weaknesses in the quality of engineering work appear to have been pervasive throughout the organization and recent changes implemented by the licensee such as moving the engineering organization to the plant site, have not yet been demonstrated to be effective.

The licensee's engineering programs for motor operated valves, for monitoring erosion/corrosion, for installing temporary modifications, and for managing on-line system outages were identified as strengths.

Safety focus was good in the area of maintenance, and was evidenced by effective planning, scheduling, and conduct of corrective, preventive and predictive maintenance activities. Identification of problems was mixed and resolution was at times slow. For example, inadequate procedures and personnel errors have resulted in missed technical specifications (TS) surveillances. Overall equipment performance was good and has allowed the licensee to achieve a high plant availability factor. With the exception of a condenser tube rupture that caused a plant shutdown and burnt control rod drive cable pin connectors that caused two power runbacks, few equipment failures were noted. The quality of maintenance was mixed with generally good performance, but with some procedural adherence and personnel errors, particularly with regard to surveillance testing.

Overall performance in the plant support area of radiological controls has been superior with strong programs for minimizing occupational dose, improving plant material conditions, facilitating teamwork, and in the use of technological advancements. Also, both quality assurance audits and self assessment efforts in the radiological control area were effective.

OVERALL ASSESSMENT SCOPE AND OBJECTIVES

This Integrated Performance Assessment of Crystal River Unit 3, is being performed in accordance with NRC Inspection Procedure 93808 "Integrated Performance Assessment Process" and is being supplemented by a limited Safety System Functional Inspection (SSFI) type review of the decay heat removal and corresponding support systems. The assessment is broken up into two phases; a preliminary assessment performed in NRC headquarters, and a final assessment which will be performed on-site. The assessment is being conducted by the Special Inspection Branch of the Office of Nuclear Reactor Regulation. The preliminary assessment was performed during the weeks of June 3 and June 10, 1996. The on-site assessment is scheduled to begin on July 8, 1996.

The assessment objectives are to identify programmatic and performance strengths and weaknesses in the areas of Safety Assessment/Corrective Action, Operations, Engineering, Maintenance, and Plant Support. The team's review in plant support will be limited to the area of Radiological Controls and Health Physics. The preliminary assessment is based on an in-office review of NRC inspection reports, licensee event reports, NRC and licensee performance indicators, enforcement history, regional assessments, and licensee internal and external assessments. The results from this phase of the assessment are contained in the following preliminary assessment report. References to source documents are contained throughout the report. The reference list is attached as Appendix A to the report.

The team's SSFI like review of the Decay Heat Removal System will be used to assess the effects that any previous weaknesses in the original design or in subsequent engineering work may have had on current system operability. Questions resulting from the team's preliminary review of design information pertaining to this system are attached as Appendix B to this report.

Following the issuance of this preliminary assessment report, the team will attempt to validate its conclusions via a performance based, on-site assessment. The results of this phase of the assessment will be integrated with those of the preliminary assessment and documented in a Final Assessment Report which will be issued following conclusion of the on-site visit. Included in the Final Assessment Report will be recommendations on where to focus future NRC inspection effort. These recommendations will be depicted on a Final Performance Assessment/Inspection Planning Tree.

ASSESSMENT METHODOLOGY

During the preliminary assessment, the team evaluated the Crystal River inspection record and performance history for a two year period spanning June 1994 to June 1996. Conclusions drawn from this review were then compared with the conclusions contained in licensee internal and external assessment reports. Where the conclusions were relatively consistent, a performance rating of either decreased, normal, or increased inspection was given to the individual elements. These ratings correspond to superior, good, or weak performance in the elemental areas. Where the conclusions obtained from the team's review of inspection and performance data differed significantly from those described in the licensee's internal and external assessments, or where

sufficient information was not available to come to a meaningful conclusion, individual elements were rated as being indeterminate. Also rated as indeterminate were areas which appeared to be weak during the initial rating period but for which substantial corrective actions have been taken. In these cases, it was not clear whether the corrective actions taken had been effective at resolving the areas of concern. Ratings for the overall performance areas of Safety Assessment/Corrective Action, Operations, Engineering, Maintenance, and Plant Support are not addressed during the preliminary assessment phase.

The results obtained from the preliminary assessment will be used by the assessment team to develop individual on-site assessment plans for each of the major assessment areas. The areas in which the team will focus during the on-site review will be those areas rated as indeterminate and those areas where the inspection or performance data record indicated potential performance weaknesses.

Following the on-site phase of the assessment, the team will issue a Final Performance Assessment and Inspection Planning Report. This report will contain an assessment of each elemental and overall area. The final report will also contain recommendations for future NRC inspection. These recommendations will be depicted on a Final Performance Assessment and Inspection Planning Tree and will be based on an assessment of overall plant performance, performance in the individual elemental area, and relative safety significance. The inspection recommendations will be scaled to what would be normal NRC inspection effort at a single unit site.

1.0 SAFETY ASSESSMENT AND CORRECTIVE ACTION

1.1 Problem Identification

Precursor cards and problem reports

The licensee's precursor card (PC) and problem report (PR) programs have been effective at identifying specific equipment, personnel, and program problems. Additionally, inspection reports indicated that management had placed increased emphasis on identification of problems and issues during 1995. The PCs were used to identify and correct minor initial concerns, incidents or conditions which may result in minor corrective actions and the PRs were used to document more significant conditions or events which may impact plant safety, operability, NRC regulations, and licensing conditions. Review of these two programs concluded that the licensee had encouraged the use of PCs to identify potential issues during this assessment period. This was evidenced by a 1,400 percent increase in the number of PCs between the years 1994 and 1995 (ref. 26).

Although the PR program appeared adequate in the identification of problems at the plant, there were a few instances in which the licensee did not initiate a PR. For example, licensee personnel did not initiate a PR to document the

failure of a control room emergency ventilation test (ref. 38) and did not issue a PR at the time a flaw was found in the pressurizer weld (ref. 19). Additionally, there was a concern with the lack of timely resolution to an operator identified discrepancy with the mispositioned annunciator link (ref. 35).

QA audits

The effectiveness of the licensee's independent assessment programs to proactively identify performance issues has been mixed, with some assessment efforts having identified meaningful issues while others have not. Previous inspection reports have generally contained positive comments regarding the ability of QA audits to identify issues. For example, a report stated that an audit of the Nuclear Operations Engineering Organizations was thorough and comprehensive in nature (ref. 26); that an audit of the instrument air system contained good substantive technical issues with respect to the instrument air system's ability to function as specified in the Final Safety Analysis Report (FSAR) (ref. 11); that an audit identified 66 recommendations to improve the conduct of Operations department activities (ref. 4); and that an audit of the EP preparedness program was thorough and detailed (ref. 37).

The IPAP team's review of selected licensee audits and surveillances indicated that some of these documents contained limited assessment information on the performance of various licensee programs, contained a limited number of specific findings, and did not integrate individual issues into a meaningful assessment of performance (refs. 108-115). Some improvement in the quality of audits and surveillances over the two year review period for this assessment was noted. In the cases where recommendations were made, it was unclear how they were tracked and if corrective actions were taken. The effectiveness of the licensee's QA audit program will be reviewed during the team's on-site inspection.

Line organizational self assessments

The licensee has not uniformly conducted site-wide line organizational self assessments. While some line organizations have conducted various self assessment activities, the quality of these assessments has been mixed, with the better self-assessment usually involving consultants or individuals from other utilities. The team will review the licensee's process for conducting line organizational self assessments during the on-site inspection.

Overall performance was rated as being indeterminate in this area.

1.2 Problem Analysis and Evaluation

Performance Assessment Programs

Weaknesses in the communication of performance standards, issue prioritization, and in the overall integration and trending of performance data, appears to have hindered the ability to identify, assess, and resolve

the more broad scale programmatic and cultural performance problems (ref. 119). As a result, some performance problems have resulted in plant events or have been subsequently identified by external organizations.

Until recently, corrective actions to performance problems were directed at lower levels within the organization, while weaknesses in management practices have not been given sufficient attention. Recent improvement in this area was noted in the licensee's response to the Management Review Panel report (ref. 116) which detailed some 49 corrective actions (ref. 117). Many corrective actions to the issues raised in that report have been appropriately directed towards management level systems and practices. The effectiveness of these corrective actions remains to be demonstrated.

Ineffective change management was cited by the licensee (ref. 118) as a root cause for many of the problems identified during the 1994 time period; however, efforts to improve the management of site issues has yet to be shown to be effective.

Conversely, the implementation of a semi-annual senior management assessment in June of 1995 was seen as a positive step in focusing organizational resources and in setting organizational priorities by creating specific management focus items. This program identified as priorities, issues associated with the operability determination process, with the effectiveness of communications, and with assessing the impact of the current 24 month operating cycle. The effectiveness of the program at achieving the desired performance improvements remains to be validated and will be reviewed during the team's on-site assessment.

Although a lower level manager assessment program has identified some relevant performance issues, recommended corrective actions were sometimes vague or non-existent, such as those regarding the findings on change management and performance measures contained in the third quarter 1995 assessment. In addition, it is not clear whether senior licensee management has accepted and endorsed these recommendations or whether the recommendations were being tracked or trended. In addition, the fourth quarter 1995 manager assessment was never completed, although a summary report was issued of problem report and precursor data. The cancellation of this assessment due to a conflict with the start of the refueling outage, raises a question regarding the licensee's management of competing organizational priorities. The effectiveness of the manager assessment program to achieve performance improvements will be evaluated during the team's on-site assessment.

A quarterly performance monitoring report is being used by the licensee to help in assessing and trending performance in human, regulatory, production, and financial areas. Based on a review of the 1st quarter 1996 report, the team identified that the program is not being used to assess performance in many of the key areas which had been previously identified as concerns, either via the organizational business plan, or via senior management assessments. For example, the program provides little data on the effectiveness of the engineering organization, corrective action plans, the plant review committee, licensed operator training, work planning, the operability determination

process, and organizational communications. It appears that only those indicators that contain readily quantifiable data are being presented on the quarterly monitoring report, regardless of the significance of the area.

Additionally, although the report states that those indicators which receive a red or yellow rating should include a discussion of planned actions to improve performance, some do not, such as the indicator for safety system failures. Also, although recent changes have been instituted to put increased effort on monitoring "regulatory performance," it was unclear whether indicators such as safety system actuations, safety system failures, and unplanned scrams would be more appropriately labeled as indicators of safety performance.

Finally, it was not clear to the team how the quarterly performance indicator report was being integrated into the licensee's overall performance assessment process. The licensee's recent formulation of a safety assessment group may be an attempt to better integrate the results of the various performance assessment programs. Further review of the functions and responsibilities of this group along with the performance indicator monitoring program will be conducted during the team's on site assessment.

Inspection reports have indicated that trending and assessment of problems identified in the licensee corrective action programs were weak (need reference). In addition, a licensee audit indicated that the manner in which data is being provided to the individual departments by the Tracking and Trending Group is not adequate to allow these organizations to satisfactorily evaluate performance (ref. 33). Also, unlike the PRs, PCs were not tracked by system or component, therefore repeat incidents with components or system were left to the memory of the cognizant engineer (ref. 26). With the notable exception of the operations area, the licensee's tracking and trending process for the Event-Free Operations Program was not clearly defined, was inconsistently applied, and could fail to identify adverse trends (ref. 31). Effectiveness of the licensee's trending program will be reviewed during the onsite inspection period.

The effectiveness of the licensee's onsite and the offsite review committee performance appeared to have improved during this assessment period. Although an earlier report indicated that the onsite Plant Review Committee (PRC) was weak, and had not prevented the return of equipment to service without any post-modification testing (ref. 5), later reports indicated that the PRC members demonstrated a strong, questioning attitude (ref. 31). Also, the offsite review committee was noted to have performed a good job of assessing plant operations and identifying issues that warrant follow-up (ref. 31).

Corrective Action Programs

Regarding the licensee's corrective action program, inspection reports indicated that the PR program was being adequately managed based on the downward trend of open PRs (ref. 26). In the past, the licensee had received criticism of the PR system from the NRC, external organizations, and from an internal audit. The PRs lacked event details, safety consequence evaluations and root cause analysis (ref. 92). However, review of inspection reports and licensee event reports (LERs) indicated that there were some recurring events.

These events indicated that a thorough root cause analysis may not have been performed in some instances. Examples of these repetitive events included: inadequate flow instrumentation in the high pressure injection line piping (ref. 37); problems with properly manning the fire brigade (ref. 17); and problems with maintaining the control complex habitability envelope (ref. 60, 93, 50, 53). Also, an audit appeared to indicate that improvement in the area of problem analysis and evaluation was needed. The audit stated that there needs to be less emphasis on answering precursor cards and counting the numbers assigned to individual organizations and increased emphasis on identifying why the condition occurred and how to effectively address and prevent it from occurring again (ref. 33). The team will review the quality of root causes performed by the licensee during the on-site assessment.

Overall performance was rated as being indeterminate in this area.

1.3 Problem Resolution

Inspection reports indicated that the licensee had been ineffective in resolving numerous technical and performance-related issues. This has resulted in either untimely or ineffective resolution of issues, for example: repeated problems with high pressure injection (HPI) line flow instrumentation which was not adequate to allow operators to balance the flow through the four HPI lines (ref. 37); repeated problems with proper manning of the site fire brigade (ref. 18); design deficiencies which were not corrected in a timely manner (ref. 36); over 200 EOP items which had been identified, but had not been addressed (ref. 24); inadequate revisions to Curve 8, maximum make-up tank over-pressure; inadequate review of problem report 94-149; inadequate corrective action for required tank volumes (ref. 36); and untimely resolution of inconsistencies between pump test acceptance criteria and the FSAR for 24 pumps which had not been resolved since 1990 (ref. 26). Furthermore, inadequacies in the corrective action program appeared to be longstanding in that it was identified as a concern in the SALP report for the time period April 28, 1991, through August 22, 1992 (ref. 92). The team will conduct further review of these and other events to assess the licensee's performance in this area.

The reports also indicated that management's responsiveness to and oversight of significant issues needed to improve. Issues such as: problems with the operability determination process; resolution to the control complex habitability envelope; effective root cause evaluations; and existence of a large Request for Engineering backlog indicated that management responsiveness and oversight of these issues warranted further improvement (ref. 31). Also, management's ineffective resolution to the operators' concerns regarding the make-up tank over-pressure curve contributed to the operators performing an unauthorized test (refs. 36 and 28). The inspectors determined that the licensee had inadequately revised a procedure for manual operation of a decay heat removal valve even though the operator's use of this procedure caused an over-cooling transient (ref. 94).

Reports indicated some corrective actions taken by the licensee were thorough and had adequately resolved the identified issues (refs. 17 and 37). In particular, the corrective actions taken later in the assessment period appeared adequate.

Increased inspection is recommended in this area.

2.0 OPERATIONS

2.1 Safety Focus

Overall, inspection reports indicated that safety focus was adequate. However, unauthorized tests conducted by licensed operators demonstrated significant weaknesses in safety focus, management oversight, and management involvement. The tests were performed to validate concerns with an operating curve for the make-up tank (refs. 11 and 28), and revealed the licensee had not established clear priorities regarding safety concerns raised by operators. The effectiveness of recent initiatives taken by the licensee to improve safety focus will be reviewed during the team's on-site assessment.

The quality of internal and external communications within the area of operations has been weak. For example, a plant transient was caused because maintenance and engineering personnel failed to notify operators that they had initiated maintenance on a heater drain level control component (reference 24). Untimely problem resolution of an anticipated transient without scram (ATWS) annunciator alarm was caused by poor communication between operators and maintenance personnel (ref. 8). In addition, problems have occurred because operations management has not adequately defined and communicated expectations regarding the conduct of tests, the use of procedures, and the operability determination process (refs. 28, 36, 8). Also, a quality audit revealed operators perception that vertical communication was poor (ref. 95-09-OPS, QPA95-0041). The effectiveness of licensee efforts to improve internal and external communications will be reviewed during the team's on-site assessment.

Although in general, inspection reports noted conservative operating decisions, there were examples regarding non-conservative decisions. For example, the licensee decided not to declare both decay cooling heat exchangers inoperable when it was identified that plugging from crud buildup could have affected the ability to develop design basis flow through the heat exchangers (ref. 15). Inspection reports identified several examples of conservative decision making including the decision to postpone the motor driven emergency feedwater pump outage until auxiliary steam became available (ref. 24), and to declare an emergency feedwater pump inoperable when packing leak-off appeared to be insufficient (ref. 35). Additional conservative examples were also identified (refs. 18, 33, and 37). Late in the inspection period, management communicated through business plans that nuclear safety and conservative decision making were top priorities (ref. 37). The effectiveness of these efforts was not assessed due to their recent development (ref. 37), but will be reviewed during the team's on-site assessment.

Inspection reports indicated that efforts to improve operability decisions have not been effective. A detailed and thorough process with rigorous guidance for making operability determinations had not been implemented (ref. 31). The status of the licensee's efforts to establish a rigorous operability determination program will be reviewed during the team's on-site assessment.

Overall, management of component outages was noted to be effective (refs. 13, 8, 18, 24). Routinely, inspection reports noted that prior to removing safety significant equipment from service, an impact evaluation was performed to assess the consequences of the equipment's removal from service. In one example, contingent actions were developed to quickly return a raw water pump to service and preclude personnel from damaging remaining equipment (ref. 16). However, poor coordination of system outages resulted in dual train inoperability of the decay cooling system (ref. 33). This situation occurred in spite of controls to review scheduled activities in order to identify and prevent this type of situation, which specifically addressed diesel generator maintenance (ref. 26).

The inspection record indicated that compliance with, and management of, technical specification limiting conditions of operation was not always effective. For example, operators failed to enter the limiting condition for operation when a emergency diesel generator was removed from service (ref. 14). In another example, operators correctly identified that guidance in a procedure was incorrect regarding entering a limiting condition of operation during testing of emergency safety feature actuation logic matrices (ref. 7). There were many examples cited where equipment was returned to service appropriately (refs. 4, 18, 24); although, in one instance, return to service activities for the reactor building sump did not adequately remove debris (ref. 4).

Overall performance rated as indeterminate in this area.

2.2 Problem Identification and Resolution

Problem Identification

Overall, the inspection record indicated that problem identification was adequate (refs. 8, 18, 34, 24). For example, operators identified problems with routine and emergency operating procedures which could have resulted in technical specification violations or safety system inoperability (refs. 33 and 37). However, instances were noted where operators did not initiate timely corrective actions. For example, a work request for an alarming ATWS annunciator was not initiated in a timely manner (ref. 8), and an uncontrolled breach of the control room envelope was discovered by an inspector. In addition, the licensee's quality organization identified that operations personnel were not documenting problems in the Precursor Program (94-10-OPMN, QPA94-0058). While more recent audit findings indicated that site wide personnel are identifying a significantly higher number of problems using the precursor program (ref. 26), it was not clear if improvements had been made within the Operations division.

The effectiveness of operations initiated self assessments was indeterminate due to the lack of information provided to the team in this area. Inspection reports did not reference any self assessment activities in the operations area.

The Operations Event-Free Operations trending program was noted to be well established and was becoming more useful as data was expanded. The licensee has also formed a committee to develop consistent policy for procedural use (ref. 31); however, the effectiveness of the effort could not be measured since it had been recently implemented. The effectiveness of operations self assessments and efforts to increase problem identification will be reviewed during the team's on-site visit.

Problem Resolution

Performance in this area was indeterminate. Efforts to implement corrective actions were slow in some instances. For example, in one instance, the PC review committee took a month to initiate resolution to a concern identified by an operator regarding an out of service annunciator (ref. 35). Inspectors reviewed the status of the licensee's emergency operating procedures enhancement program and associated corrective actions, and noted that a final corrective actions schedule had not been developed (ref. 31). In addition, a test conducted by licensed operators to validate concerns with the make-up tank operating curve indicated that efforts to establish programs to resolve adverse conditions were not effective (ref. 36). There were also repeated problems with maintaining the control room envelope boundaries (refs. 18 and 24). Corrective actions taken to address weaknesses in the requalification program were, however, found to be effective (refs. 12 and 34). Later in the review period, the licensee implemented corrective actions for several problem areas. The effectiveness of these initiatives could not be fully assessed. The licensee's efforts to improve problem resolution effectiveness will be reviewed during the team's on-site assessment.

Overall performance was rated as being indeterminate in this area.

2.3 Quality of Operations

During power operations, operator performance appeared to be good (refs. 4, 5, 8, 14, 16, 18) with the exception of the issues surrounding the unauthorized make-up test which resulted in operation outside the system design (ref. 28).

Performance during outages was considered to be adequate in that reactor start-ups and shutdowns were well controlled (refs. 5 and 8). In addition, refueling outage preparations for mid-loop operations were found to be adequate (ref. 38), with the exception of a few problems. For example, a senior reactor operator was found to be inattentive to refueling duties, and an decay cooling pump was inadvertently actuated due to poor self-checking by an operator (ref. 38). In addition, operators exceeded the reactor coolant system cooldown rate because they chose a less accurate temperature indicator (ref. 35). Response to events, while few examples were documented, was noted as a strength (ref. 23).

There were examples of good shift briefs for reactor shutdown (ref. 35) and log keeping regarding documentation of plant transients (ref. 23). However, weaknesses were identified with log keeping when an operator closed the wrong spent fuel pool cooling valve, and when a review of logs was conducted following the test of the make-up tank operation curve. (ref. 36). The effectiveness of shift-turnovers will be reviewed during the team's on-site assessment.

Operations coordination with other organizations was weak in some instances. There were examples where operators did not effectively resolve a problem with an ATWS annunciator which allowed the ATWS system to be bypassed at a higher than designed power level (ref. 8). Also, poor coordination with maintenance and engineering personnel resulted in a plant transient during maintenance on a heater drain level controller (ref. 24). In one case, good coordination between operations and maintenance was observed for troubleshooting of a control rod drive power supply failure (ref. 11).

Overall, performance of equipment clearances was generally good. Numerous examples were noted where equipment was taken and restored to service uneventfully (refs. 25, 26, 34). The licensee's program for control of troubleshooting will be reviewed during the team's on-site assessment.

Normal inspection is recommended in this area.

2.4 Programs & Procedures

Overall, operators adherence to procedures and the quality of procedures were weak, and was indicative of a failure to establish clear expectations regarding the conduct of tests, response to alarms/annunciators, self-verification, and quality of procedures.

Several procedural problems were self identified by plant operators including an example where a surveillance procedure did not include requirements to enter the applicable limiting condition for operation during 4 KV undervoltage relay testing (ref. 24). In another example an operator identified a emergency safety actuation logic matrix surveillance procedure inappropriately allowed delayed entry into a technical specification limiting condition for operation (ref. 33). An inadequate procedure for flow balancing to make-up pumps resulted in pump operations outside system design (ref. 31).

Operators failed to follow procedural guidance to enter a technical specification limiting condition for operation for diesel generator inoperability and did not verify the offsite availability of power sources (ref. 31). During cooldown of the reactor coolant system operators did not control cooldown with appropriate temperature indication, as directed by operating procedures, and exceeded the technical specification cooldown rate (ref. 35). Late performance of a technical specification required surveillance was the result of poor procedural implementation by operators (ref. 56).

Operators performed a test to verify concerns with the make-up tank operating curve without procedural controls (ref. 36). The same test, which resulted in

operation outside the make-up tank operating curve limitations, revealed that management had not provided adequate guidance for determining when procedures are required for non-routine evolutions. Also, guidance had not been established for alarm response time expectations, and for determining when evolutions constitute experiments (ref. 36). A decay cooling pump was inadvertently started due to inadequate self verification by an operator (ref. 38). The emergency operations enhancement program was noted to continually identify issues where inadequate guidance was translated to procedures (ref. 34 and 24). Outside of the emergency operating procedure enhancement program, the inspections reports did not identify any significant progress in improving performance in this area. Procedural adequacy and implementation will be reviewed during the team's on-site visit.

Increased inspection is recommended in this area.

3.0 ENGINEERING

3.1 Safety Focus

The licensee's engineering organization has not always demonstrated a good safety perspective relative to plant operations. Examples included: not identifying errors and non-conservative assumptions for the make-up tank pressure/level curve which permitted the plant to be operated outside the design basis (refs. 28 and 35); instrument set-points for many safety related instruments that were set non-conservatively with respect to TS allowable values (refs. 41, 11 and 18); not identifying the lack of adequate net positive suction head to low pressure injection pumps for a postulated design basis accident (refs. 54, 24, and 28); the Plant Review Committee's (PRC) acceptance of the operability of the auxiliary feedwater pump following modification work without sufficient post modification tests (ref. 5); and failure to notify the NRC in a timely manner of a flaw in the pressurizer surge line nozzle- to-lower pressurizer head weld which resulted in a principal safety barrier being in an un-analyzed condition (ref. 19). With a large number of the available resources dedicated to the resolution of design basis issues, day-to-day issue support has been reduced (ref. 26).

The licensee's service water system self assessment identified substantial weaknesses in numerous areas including heat exchanger performance monitoring, the implementation of Generic Letter 89-13 actions, and service water system flow balancing problems. The licensee's initial response to the self assessment did not have the appropriate sensitivity to findings or conditions that questioned equipment operability (ref. 15).

Written operability evaluations have often been very brief with few details (ref. 31). The licensee's new operability evaluation process lacked adequate reviews to ensure that conservative operability determinations were made. For example, the supporting calculation performed to verify operability concerns with respect to an unsecured reactor building sump grating installed over the emergency core cooling system (ECCS) pump suction pit, used an incorrect methodology and no independent review or verification was performed (ref. 36).

In some instances, the licensee's Nuclear Licensing Department has provided non-conservative technical specification interpretations for the plant operation. For example a licensing position was taken that stated instrumentation set-points that exceeded TS allowable values, but did not exceed safety evaluation limits, would not cause safety related equipment to be declared inoperable (ref. 11). Also, a position taken by the Nuclear Licensing Department delayed the reporting of a breach of the control room habitability envelope which resulted in the control room emergency ventilation system being outside of its design basis (refs. 18 and 25). A recent position taken by the licensee concerning the required availability of systems to prevent the precipitation of boron in the reactor core following design basis loss of coolant accidents, was without adequate technical basis, and appeared to be contrary to both the original design basis of the plant and to previously stated regulatory positions (ref. 90).

The licensee's use of probabilistic risk assessment was a strength, including the use of an on-line risk monitor to evaluate risk significance of plant configurations on maintenance and operational activities (ref. 26).

A review of recent operability evaluations, communication of management expectations, and management involvement in decision making will be conducted during the team's on-site assessment.

Increased inspection is recommended in this area.

3.2 Problem Identification and Problem Resolution

A number of design issues have been identified by the licensee which revealed instances where the plant had operated outside the design basis. Specific examples included the following: circuits for controlling "B" train emergency feedwater to the steam generator were not separated from "A" train to meet Appendix R requirements (ref. 78); the circuitry to close post accident hydrogen purge valves was not isolated from non-safety circuits (ref. 79); significant service water system and component flow concerns resulting from a loss of coolant/loss of offsite power coincident with single failure of the dc system (ref. 82); vacuum breakers for the borated water storage tank (BWST) did not have adequate relief capacity (ref. 77); and during a LOOP, high pressure injection pumps would be required to rely on non-safety related backup dc-powered lube oil pumps for lubricating oil (ref. 69).

There were a few examples where the engineering staff did not identify plant issues including the following: the NRC identified that the BWST level designated in emergency operating procedures for swap over from the BWST to the reactor building (RB) sump had not taken vortexing into consideration (refs. 28 and 36); NRC inspectors identified that the control complex habitability envelop was not being maintained in accordance with assumptions used in the design calculations (refs. 25, 31 and 53); and a deviation from the design commitments was identified for the technical support center emergency ventilation system (ref. 31).

The licensee has performed several good self assessment efforts within the engineering area including a good independent audit of the GL 89-10 program

(ref. 7) and two Nuclear Engineering and Projects (NEP) self assessment audits which identified issues pertaining to configuration control and design interfaces (ref. 89). A QA audit of engineering appeared to be thorough, with the auditors making substantive technical observations and findings (ref. 26). The NRC service water inspection team identified that the licensee's service water self assessment identified a lot of significant issues, including the fact that the licensee had failed to implement GL 89-13 commitments; however, the licensee's response to the audit findings was inadequate. Subsequent inspection by the NRC of the service water system has identified additional problems (refs. 15 and 30).

In the area of problem resolution, the licensee's performance has generally been weak and not timely. For example, a problem report regarding the inconsistency between ASME Section XI pump test acceptance criteria and the FSAR identified in 1989 has not yet been completed (ref. 20). Also, a weakness was identified regarding the lack of timely follow-up on a 1992 concern regarding operating with both steam generator cross tie valves open at the same time. This safety issue which had the potential of defeating the main steam line isolation was not reviewed until 1995 (ref. 33). The licensee also failed to implement adequate corrective actions for an issue involving non-conformance with a design basis accident requirement which required that high pressure injection (HPI) instrumentation be designed to allow the operator to balance the flow in the four HPI lines. In 1989, the licensee determined that the design did not provide this capability. In 1996, the licensee identified that this issue had not been resolved (ref. 37).

Several safety significant issues and the backlog of Requests for Engineering Assistance increased during the assessment period. This posed a significant challenge to the engineering organization and may have contributed to the weak performance. In 1995, the licensee consolidated its engineering staff at the site and integrated the Nuclear Plant Technical Support organization into the NEP organization. The licensee also initiated corrective action programs and management processes to enhance human performance and reinforce an improved safety attitude (ref. 91).

Normal inspection is recommended in Problem Identification and increased inspection is recommended in Problem Resolution area. The team will review the effectiveness of the corrective action process, root cause analysis, the prioritization process, engineering backlogs and the thoroughness of licensee assessments during the on-site phase of the assessment.

3.3 Quality Of Engineering Work

Design engineering has often been ineffective in providing support to plant operations. For example, inadequate and incorrect design information contained in the makeup tank operating curve and calculations allowed the plant to operate outside of its design basis. Engineering had to revise the calculations and operating curves twice to address the issues (refs. 44 and 36). Untimely engineering support resulted in physical implementation of modifications without supporting design calculations and without procedures to properly implement and verify that the modifications would function as intended. In some cases the design changes were performed through work orders

without any design control documents (refs. 4 and 91). The inspection reports indicated that the licensee was not updating the Updated Final Safety Analysis Report (UFSAR) to reflect the current design basis of the plant. For example, modification to the interlock features for the BWST isolation valves, the license amendment No. 134 for spent fuel pool, and removal of engineered safeguards closure signal for the containment purge valves were not incorporated in the UFSAR (ref. 37).

Some 10 CFR 50.59 evaluations for plant modifications were weak. For example, a 10 CFR 50.59 evaluation for the 480 Vac transformer replacement modification concluded that no unreviewed safety issues existed without resolving open items. Additionally, safety evaluations were not performed for the battery charger and inverter replacement modifications, main steam system temporary modification, and MUV-65 valve and piping components modification (ref. 38).

While some modifications were detailed and thorough, numerous weaknesses were identified in the design control process for plant modifications and engineering calculations. For example, the modification to the standby feedwater pump recirculation line neither received cross discipline review nor PRC review (ref. 35) and nineteen field change notices were needed to address design problems for service water isolation for the reactor coolant pump modification (ref. 26). Also, not properly identifying all procedures requiring revision coincident with the installation of a plant modification for ATWS resulted in bypassing the system at a higher power level than designed (ref. 8). Incorrect design inputs for a battery charger modification led to post modification tests that did not verify operation at the correct degraded voltage level (ref. 38). Lastly, non-conservative calculations were performed to demonstrate adequate capacity for fire water storage tanks and others (ref. 24).

Weaknesses were also identified in the quality of licensing submittals (ref. 91). For example, during the review of a proposed amendment request to change the plant TS to permit the use of voltage and dimensional-based steam generator tube repair criteria, the NRC staff noted that the documents submitted contained many errors (ref. 38).

Increased inspection is recommended in this area. The team will review recent modification packages and calculations including 10 CFR 50.59 evaluations, and engineering evaluations of plant issues during the on-site phase of the assessment.

3.4 Programs and Procedures

The licensee has effectively implemented several engineering programs, including: a pro-active erosion/corrosion program to ensure that thinned piping is identified before failure (ref. 1); a satisfactory GL 89-10 motor operated valve (MOV) program (ref. 7); a well managed on-line system outage program (ref. 14); and a sound temporary modifications program (ref. 31). The station blackout modifications, procedures and NRC staff recommendations were implemented adequately (ref. 6).

System engineers have performed periodic walkdowns of their systems and were responsible for planning on-line system outages, trending system performance, and follow-up on system problem areas. The system engineers interviewed were certified on their systems and knowledgeable of the system backlog and issues (ref. 26).

However, programmatic weaknesses were identified in a few engineering programs. For example, the NRC identified weaknesses in the implementation of administrative and technical procedures for the inservice inspection program (refs. 1 and 38); numerous deficiencies were identified in the instrument setpoint control program (refs. 18 and 22); and weak procedures and inadequate implementation of the 10 CFR 50.59 program was noted (ref. 38).

Overall, engineering performance of programs and procedures was indeterminate. The team will review engineering procedures, the system engineering program, the IST program, the heat exchanger monitoring program, the 10 CFR 50.59 program, and engineering training during the on-site phase of the assessment.

4.0 MAINTENANCE

4.1 Safety Focus

Management safety focus in the area of maintenance was evidenced by effective planning, scheduling, and conduct of corrective, preventive and predictive maintenance activities. Proper safety focus was further evident by high equipment availability, high system reliability, and consideration of risk perspectives. Job briefings were routinely well planned, coordinated and efficient (refs. 4 and 6). Management, supervision, and system engineering were often involved with the more complex activities (refs. 5, 11 and 33) and there was good interdepartmental coordination to reduce unavailability of vital equipment (ref. 8).

The planning of equipment outages during operation routinely included a safety benefit analysis before a system/component outage was approved for on-line maintenance (ref. 26) The safety benefit analysis was often done by observing the effects of removing the equipment from service on the simulator, before taking the component out of service (ref. 13). The licensee has also used the control room risk monitor to evaluate the change in risk prior to removing equipment from service (ref. 25). Collectively, these were viewed by the team as good practices.

Maintenance self assessments identified some weakness in communications and work package preparation (ref. 102). Examples of weak communications identified in inspection reports included an instance when work package documentation failed to require re-attachment of emergency feedwater initiation and control instrument lines (ref. 86) and when poor communications resulted in operators failing to follow the work process controls for requesting the troubleshooting of an AMSAC annunciator malfunction (ref. 8). Additionally, operators were not aware of electrical cables that passed through the upper control complex doors causing operation outside the design basis (ref. 14) and technicians failed to notify operators that Reg Guide 1.97 instrumentation would not calibrate during the last refueling outage (ref.

31). Also, delaying the DJP-1 EDG coolant pump seal replacement from the 10 year ISI schedule resulted in an unscheduled emergency diesel generator outage due to the failure of the coolant pump (ref. 4).

Normal inspection is recommended in this area. Maintenance communications, IST scheduling and work package development will be reviewed during the on-site assessment.

4.2 Problem Identification and Problem Resolution

The licensee has conducted several self assessment activities in the maintenance area, some performed solely by outside utility personnel (refs. 95-102). The assessments conducted by licensee personnel only, were less critical (refs. 95-101), as opposed to the more in depth reviews conducted by outside personnel (ref. 8). Quality Assurance audits provided substantive recommendations; however, tracking and follow-up of audit findings were not apparent in any of the audits reviewed. Additionally, it was not apparent that maintenance department self-assessments provide criteria or standards to measure against, nor do they provide for evaluation of discrepancies or dispositioning of the findings.

Identification of problems has been mixed and resolution has been at times slow. Inadequate procedures (ref. 8) and personnel errors (refs. 23 and 18) have persistently resulted in missed TS surveillances (ref. 8). Control complex emergency ventilation dampers have repeatedly permitted leakage beyond TS allowable limits. Even though testing of the dampers revealed a capacity of only 86 % of the required flow, no problem reports or precursor cards were written, nor was the problem evaluated for reportability (ref. 81).

The licensee did not identify that first level undervoltage relay (FLUR) calibrations were not being performed in according with the T/S (ref. 18), and service water system heat exchanger bio-fouling blockage was long standing without recognition or correction (refs. 15 and 30). The licensee's self assessment of the service water system provided an opportunity to provide a thorough in depth analysis of the root causes for the identified issues yet the licensee's corrective actions were less than adequate (ref. 30).

Notwithstanding, alert maintenance technicians on various occasions have stopped their activity when identifying problems and sought appropriate solutions (refs. 31 and 18). Additionally, problem identification and resolution was enhanced by the use of the Minor Maintenance Program (ref. 95), which is designed to identify and correct most of the minor problems and prevent further degradation before failure occurs.

Normal inspection is recommended in this area. The team will review dispositioning of audit findings and resolution of identified problems during the on-site assessment.

4.3 Equipment Performance and Material Condition

Equipment operating performance has been good. With the exception of a condenser tube rupture causing a plant shutdown (ref. 35) and burnt control

rod drive cable pin connectors which caused two power run-backs to 55% (ref. 5) only two other equipment failures were noted during the period. The two equipment failures involved water intrusion in the emergency feedwater pump oil crankcase (ref. 5) and failure of the gate trigger unit in the pressurizer pressure control cabinets which caused the pressurizer heater control instrument to be out of calibration (ref. 4). Neither instance resulted in an immediate loss of design function for the equipment.

Reduced inspection is recommended in this area. The team will review foreign material controls and general material condition of the plant during the on-site assessment.

4.4 Quality of Maintenance

In general, inspection reports stated that maintenance was performed by qualified individuals in a professional manner (ref. 1). Equipment performance parameters were appropriately monitored and supervision and management involvement were often observed (refs. 5 and 24). However, there have been some repetitive human performance problems. For example, numerous procedural adherence and personnel errors associated with surveillance testing of the ATWS/AMSAC system were cited as having occurred in several departments (ref. 8). Additional concerns with procedural adherence were documented when personnel failed to test the reactor coolant pump (RCP) flywheel in accordance with inservice testing requirements, and failed to test containment isolation valves in accordance with TS and 10 CFR Part 50 appendix J requirements (refs. 40 and 42). Procedural errors noted in inspection reports included an instance where maintenance personnel inadvertently caused the actuation of the emergency diesel generator during testing (ref. 51), where technicians stroked the wrong valves by misreading the procedure (ref. 34), and where maintenance personnel improperly installed a door to the control complex habitability envelope (ref. 29).

Normal inspection is recommended in this area. The team will review the licensee's programs for providing feedback on recommended improvements to procedures and work packages, recurring problems and repetitive failures, and training during the on-site assessment.

4.5 Programs and Procedures

Maintenance programs and procedures were generally good, with an absence of problems reported with preventive and corrective maintenance procedures. It appears that additional attention may be warranted to the review of surveillance procedures as several procedural control violations were noted with surveillances of ATWS\AMSAC (ref. 8). Also, surveillance procedures were not sufficiently detailed to prevent technicians from missing required testing of the emergency diesel generator undervoltage relays (ref. 31).

Additional review may also be warranted of the Minor Maintenance Program. Although the criteria for work to be performed under the Minor Maintenance Program requires that the problem and corrective actions be self-evident and require no documentation or planning to initiate work, audits indicate that approximately 50% of the minor maintenance work conducted was troubleshooting

(ref. 95). This may be indicative of circumventing the work control process for potentially risk significant work.

Normal inspection is recommended in this area. The team will review the Minor Maintenance Program and procedural adequacy and usage during the on-site assessment.

5.0 PLANT SUPPORT

5.1 Safety Focus

The activities of the Radiation Protection staff with the apparent support of site management appeared to be advancing the effectiveness of the Crystal River ALARA program (ref. 20). Good cooperation among plant departments to maintain low occupation doses was evident based on the plant's 1995 non-outage collective dose being one of the lowest in the country (8 person-rem) (ref. 38). The licensee has completed numerous ALARA initiatives throughout the plant to continue to reduce occupational exposures and source term (ref. 38). Continued strong support and guidance should allow the site to continue to improve on its already good average occupational dose. The two recent outages have been well planned, supported, and effectively managed (ref. 38).

One area of concern was noted where the licensee management decided against a "rapid boration shutdown chemistry procedure" which would have reduced the radiation levels workers are exposed to during the refueling outage. The licensee had not planned to perform the procedure in the 10R outage in order to reduce the outage length. This procedure was used very effectively during the 9R outage. However, the licensee shut down the reactor on February 16, 1996, due to TS issues. The licensee decided to begin the 10R at that time, which was approximately two weeks earlier than scheduled. Conditions at shutdown resulted in some crud burst and the licensee was able to get more time for filtration than the planner had made available on the outage schedule. This unexpected window of opportunity allowed for a clean-up and reduction in the source term that would be consistent with that obtained during the 9R outage (refs. 20, 38, 104, 105, 106).

Management placed emphasis on improving and maintaining the material conditions by actively reducing contaminated areas; for example, out of a total area of 83,458 ft^2, only a maximum of 2,148 ft^2 was posted as contaminated (ref. 38).

Reduced inspection effort is recommended in this area. The team will review selected 10R outage activities to look at the ALARA program, procedural adequacy, and procedural adherence during the on-site assessment.

5.2 Problem Identification and Resolution

The site's Quality Assurance, audit, and surveillance programs and the radiation protection self-assessment program were well organized and provided effective, oversight of all areas of the radiological program. These audits consistently identified substantive issues and problems, and tracked appropriate corrective actions. The QA audits were comprehensive in scope,

conducted by competent staff, and were well planned and documented; the feedback (lessons learned and items for improvement) is clearly communicated (refs. 20 and 107).

Likewise, radiological self-assessments were comprehensive, technically astute, and well documented. One excellent example of a critical, effective self-assessment was the "Health Physics Critique and Lessons Learned on the CR-3 Refuel 9."

Reduced inspection effort is recommended in this area. The team will review the status of the recommendations made in the "Crystal River Unit 3 Radiation Protection Annual Review" during the on-site assessment.

5.3 Quality of Plant Support

The radiological support program provided good job coverage and technical support to operations and crafts, during normal and outage conditions. One noteworthy item which demonstrated the plant staff's ability to develop a good work plan with radiation protection (RP) and ALARA considerations, work well as a team, and complete the job safely was the planning and cooperation exhibited during the ISI activities during the 10R refueling outage. The work involved the UT examination of the reactor vessel and the core support assembly. The cooperative RP and ALARA efforts associated with the move were excellent (ref. 38).

The licensee evaluated and utilized technological improvements in remote radiation monitoring equipment, dosimetry, visual monitoring, and communication equipment to better control and assess radiological conditions and lower personnel exposures (ref. 20). The licensee effectively uses numerous ALARA techniques, including temporary shielding, hot spot elimination, remote high radiation area surveillance, teledosimetry, air conditioning the containment building, and the installation of several permanent platforms in the reactor building (ref. 38). The licensee adequately supports programs for external dose controls, with their computerized radiological work permit program titled Radiological Data Management System (ref. 20). The major revision to 10 CFR Part 20 was successfully implemented. As part of the implementation of the revised 10 CFR Part 20 the licensee implemented a "total risk" approach to worker doses from internal and external exposures. This program resulted in a significant reduction in respirator use, while maintaining a low total dose with proper use of engineering controls. A few additional personnel facial contaminations have resulted from this practice (ref. 20).

Reduced inspection effort is recommended in this area. The team will review selected aspects of the licensee's RP program against the description in the FSAR during the on-site assessment.

5.4 Programs and Procedures

The site has effective effluent and environmental control programs, with well trained, knowledgeable health physics technicians. The licensee's operation of the radwaste/effluent installed systems and equipment were effectively used

and were operated within their design criteria to make effluent releases that were as low as reasonably achievable (ref. 29). A comparison of the activity released from liquid and gaseous effluents for 1991, 1992, 1993, and 1994 found no significant changes (ref. 29, SALP February 1996). The NRC Region II mobile laboratory performed a comparative measurements inspection of the licensee's ability to sample and analyze reactor coolant and other liquid and gaseous samples from various plant systems. It was concluded that the licensee maintained a high capability to analyze samples (ref. 29).

The radwaste processing and shipping programs were well documented and conducted in a competent, professional manner by qualified technicians of the Maintenance Department. The volume and number of radwaste shipments has remained relatively constant over 1991-1994 (ref. 29). The licensee continued to focus attention on reducing the volume of radwaste generation. A good example of a multi-disciplinary team approach to problem solving was taken with members from Operation, Engineering, RP, Nuclear Facility Services, Planning, Cost Controls,and Chemistry tasked by management to identify ways to reduce the generation of radwaste (ref. 29).

One example of a failure to follow the instructions in the RWP Pre-job Briefing Pre-Exposure Indoctrination document was identified. Two of three workers failed to keep their face shields in the down position as required. This was identified by the NRC and resulted in a severity level IV NOV issued on May 24, 1996 (ref. 38). The licensee's response and correction actions need to be followed-up on a future inspection.

Reduced inspection is recommended in this area. The team will accompany the HP staff on routine survey rounds to document procedural adequacy and adherence during the on-site assessment.

APPENDIX A

LIST OF REFERENCES

Inspection Reports 1993 & 1994

Ref. No.	Insp. Nos.	Ref. No.	Insp. Nos.
1	94-11	20	95-04
2	94-12	21	95-05
3	94-13	22	95-06
4	94-14	23	95-07
5	94-16	24	95-08
6	94-17	25	95-09
7	94-18	26	95-11
8	94-19	27	95-12
9	94-20	28	95-13
10	94-21	29	95-14
11	94-22	30	95-15
12	94-23	31	95-16
13	94-24	32	95-17
14	94-25	33	95-18
15	94-26	34	95-20
16	94-27	35	95-21
17	95-01	36	95-22
18	95-02	37	96-01
19	95-03		

Ref. No.	LER	Ref. No.	LER
38	94-03	63	95-14
39	94-04	64	95-15
40	94-05	65	95-16
41	94-06	66	95-17
42	94-07	67	95-18
43	94-08	68	95-19
44	94-09	69	95-20
45	94-10	70	95-21
46	94-11	71	95-22
47	94-12	72	95-23
48	94-13	73	95-24
49	94-14	74	95-25
50	95-01	75	95-26
51	95-02	76	95-27
52	95-03	77	95-28
53	95-04	78	96-01
54	95-05	79	96-02
55	95-06	80	96-03
56	95-07	81	96-04
57	95-08	82	96-05
58	95-09	83	96-06
59	95-10	84	96-07
60	95-11	85	96-08
61	95-12	86	96-09
62	95-13	87	96-10

Ref. No.	LER
88	96-11

Additional Reports

89	NEP Audits 95-11-NEP and NCM-96-0047
90	Nuclear Licensing Letter - NL 96-0065 dated April 25, 1996 and Safety Evaluating FMS 94-0021
91	NRC Inspection Report 95-99 (SALP)
92	NRC Inspection Report 94-07
93	LER 90-07
94	NRC Inspection Report 94-02
95	Maintenance Self Assessment MSA-95-06; 9/15/95
96	Nuclear Plant Maintenance Audit Report 95-07 (QPA95-0029)
97	Maintenance Self Assessment MSA-95-04; 5/16/95
98	Maintenance Self Assessment MSA-95-05; 5/17/95
99	Maintenance Self Assessment MSA-95-03; 3/5/95
100	Maintenance Self Assessment MSA-95-02; 2/20/95
101	Maintenance Self Assessment MSA-95-01; 1/20/95
102	Entergy Operation Final Report (6/8/95) Crystal River-3 Maintenance Assessment 5/15-19/95
103	Performance Indicator for Operating Commercial Nuclear Power Reactors Data through March 1995 - Office for Analyses and Evaluation of Operational Data, USNRC
104	Crystal River Unit 3 Refuel 9 Outage Report 7/6/94
105	CR-3 Refuel 9, Health Physics Critique and Lessons Learned (no date)
106	Crystal River Unit 3 Health Physics Guide for Supporting Major Refuel 10 Milestones, 1996

Ref. No.	Misc. Rpts.
107	Florida Power Corporation: Nuclear Quality Assessments Office Audit Report for 95-04-CREW, Audit Title: Chemistry, Radiation Protection, Environmental Monitoring and Waste 5/22/95.
108	QA Audit Report# 94-10-OPMN, Audit Title: Nuclear Operations and Maintenance.
109	QA Audit Internal Audit# 96-01-POP, Audit Title: Pre-Outage Preparations.
110	Mid-Outage Self Assessment of Quality Assessment Activities QPD96-0002.
111	Plant Review Committee Self Assessment Report Which Includes Benchmarking Date: March 15, 1996
112	QA Surveillance Report# QPSR-96-0001
113	QA Program Surveillance Report Surv. QPS-96-0017
114	QA Programs Surveillance Report Surveillance QPS-96-0020
115	QA Programs Surveillance Report Surveillance QPS-96-0024
116	Management Review Panel - Engineering, Licensing, and Operations Interfaces, March 1995
117	Boldt Response to the MRP report of April 12, 1996
118	VPNP95-0018, "Response to the Management Review Panel Report," 2/21/95.
119	Dan Poole Management Review Panel Report, 12/31/94.

APPENDIX B

Safety System Functional Review Follow-up Questions

The following are questions resulting from the team's preliminary review of the decay heat and supporting systems. The team will follow up these questions during the on-site review.

Electrical and I&C Area Review Questions

1. Raw water pump discharge pressure is planned to be used to monitor flow blockage problems. Please provide relevant additional information of how trending would be effected. (Reference Commitment Report "COMTROL" document, Report NOCS0001, Comm No. 040438)

2. Please provide the basis for the approach taken in the root cause analysis and its resolution, including justification that the intended surveillance would represent a suitable approach. Was the possibility of premature aging evaluated? (Reference Commitment Report "COMTROL" document, Report NOCS0001,Comm. No. 040589)

3. Please provide any 10 CFR 50.59 evaluations conducted in connection with the 1985 design change for the make-up pump (Ref: LER 95-020). Why didn't the LER address the impact on safety of the combined effects of resorting to administratively controlling MUP-1B and the AC pump failure to automatically restart after a LOOP ? The worst case scenario within the plant design basis was not considered which would include a LOCA/LOOP event, a single failure of MUP-1A or MUP-1C, and a failure of the non-safety elements in MUP-1B. This scenario would result in the loss of two of the three MU pumps, which would result in inadequate flow for HPI (at least two pumps are required for HPI)

4. While consequences of failure of non-1E devices was considered for operating modes 1-6 from the standpoint of maintaining containment integrity, there was only a minimal evaluation of the potential loss of the system when it is required to operate in modes 5 and 6. The only consideration provided for modes 5 and 6 was to indicate that valves AHV-1A, -1B, -1C, 1D, are not required to operate during fuel handling accidents. The evaluation conclusion is that the system is never required to operate and therefore, that it can be fully sacrificial. Related to the objective of safe operation of the plant in the present configuration, please explain why a scheduled date for final resolution of the problem was not provided and why the evaluation of alternatives to solve the problem was to be performed more than one year after discovery of the problem (Ref: LER 95-025).

5. Corrective actions to LER 95-026 were based on the assumption that the hydraulic analysis would indicate that pump runout was not a problem. However, the results of the analysis would not be known for another two months, and no consideration was given for the case that the hydraulic analysis indicated a problem. Why is this approach to corrective action

was acceptable, since it failed to consider all possible results of future studies? Why is the scheduled date of 8/1/96 for the study of suitability of M U-27-FI considered a timely response?

6. LER 95-027 did not address potential damage to the other lines (five pipelines could have been affected) and the existence of any cathodic protection. The LER also did not address lessons to be learned related to the electrical modification installations requirements, as related to the possible need to introduce changes in order to stress special precautions when the work is done in the vicinity of underground safety related pipelines. Please provide information on the Feb. 96 follow up actions on root cause analysis and permanent fix. What is the impact on compliance with the single failure criterion of a loss of the single recirculation line?

7. Provide relevant information for set-points that were classified as Categories 3 and 4, which were judged to not require error tolerances (Ref. LER 94-006, Rev.4).

8. The root cause analysis of the event, as documented in the LER 93-002, Rev. 2, appears to be incomplete. The lack of a disconnect means between startup and backup transformers prevented the use of backup transformer as source of power to ES buses. Why was the offsite transformer not lined up to serve ES buses to prevent loss of decay heat pumps? Was this operating set up in accordance with procedures governing the offsite source operation? What operating procedure governs the restart of the decay heat removal pump after a loss of offsite power? Was this event response in terms of the pump restart in compliance with operating procedures?

9. The licensee's conclusion that a single test on one battery charger unit was sufficient to qualify other similar components appears to be contrary to accepted practice, constituting a potentially non-conservative approach. Clarifications are needed to establish the most critical operational requirement for the battery chargers. It is not clear that the analysis included the conditions derived from minimum 230 kV system voltage applied to the high voltage side of either the backup transformer, or the offsite transformer, whichever one results on lowest possible voltage available at the input of the charger. It is also not clear how the Charger load under ES is calculated as being only 68 Amps.. Provide the loading calculation for review. Please assess the safety impact of present operating conditions of the battery chargers. (Ref.LER 96-012)

10. Please explain why accuracy information on the digital multimeter, digital calibrator, and digital gauge was retrieved from VSMF microfilms, rather than from controlled documentation. Was there any other data obtained from uncontrolled documents? Please provide the following information relative to reference B of the Calculation, titled "Crystal River Unit #3, Instrument String Error/Setpoint Determination Methodology, Document I-90-0017, Revision 1":

1. Does document conform with NRC RG. 1.105, Rev.2?

2. What is the methodology for drift error data collection and trending?

3. What are the criteria for the determination of confidence levels, use of field data, and/or manufacturer's specifications?

(Ref. Setpoint Calculation I-91-0057, Rev.4).

11. Please provide packages on implementation of the following commitments from Commitment Report "COMTROL" document, Report NOCS0001):

005587, 040219, 040438, 040589, 040752, and 060480.

Mechanical Area Review Questions

1. Root Valves DHV-50 & -62 are shown as NO on P&IDs. This appears to be in conflict with NOTE 3 which states, that root valves are to be attended when open for testing and re-closed after testing is complete.

2. The reactor building maximum predicted elevation for Post-LOCA flooding is 101.656 ft. What are the flooding sources, methods of detection, and isolation? (Ref. DHR EDBD, Section 1.3).

3. What are the bases for design temperature change from 650°F to 300°F for CF check valves (Ref. DHR EDBD, Section 2.0).

4. What caused the change of the heat load from $125*10^6$ to $110*10^6$ BTU/hr? (Ref.DHR EDBD, Section 2.0).

5. Were the LOCA and containment temperature/pressure analyses revised to reflect increase of the BWST maximum temperature from 90°F to a new value? What are the means of temperature control to assure the BWST limits 40°F to 100°F? (Ref. DHR EDBD, Section 2.0).

6. How is the maximum combined leakage limit requirement (not to exceed 0.5958 gph) implemented for DH and BS systems? (Ref. DHR EDBD, Section 2.0).

7. EDBD states that DHV-34 and DHV-35 valves are NC per Appendix R commitments. P&ID shows these valves as NO. (Ref. DHR EDBD, Section 3.0)

8. DHV-42 and DHV-43 valves are required to be closed during the injection phase. Is there a closing time limit? If yes, how is it verified? No value was provided in the EDBD (Ref. DHR EDBD, Section 3.0).

9. Are the (thermal) relief valves DHV-17, DHV-28, DHV-37, DHV-38 and DHV-44 and the (vacuum) relief valves DHV-69 and DHV-70 included in the IST program? How and when were they last tested? (Ref. DHR EDBD, Section 3.0)

What are the means of the over-pressure protection (other than thermal) for the DHR system?

10. Temporary change ABD TC No. 208 dated 5/4/92 was not incorporated in the revision 5 of EDBD (Revision 5 was issued on 6/8/94). What is the impact of this change not being incorporated in the EDBD? It appears, that this change cannot be incorporated in the EDBD as it is currently formatted.

11. What is the calculated maximum level? Please provide a copy of MAR 90-06-10-02 (Ref. Temporary change EDBD TC № 400 dated 8/23/95).

12. What were the values used in the FSAR Chapter 14 analysis for DH & BS flow rates?

13. LCO 3.5.3.C.1 requires the plant to be taken from Mode 4 to Mode 5 in 24 hours. Please provide a copy of a calculation which demonstrate that this LCO can be implemented with one DHR train at a maximum DC temperature.

14. Please provide a copy of non modification related safety evaluations, engineering evaluations, engineering work requests, TS interpretations for DH, DC & BS systems.

15. Please provide packages on implementation of the following commitments from Commitment Report "COMTROL" document, Report NOCS0001):

    002942, 005984, 040209, 040217, 040604.

16. Can EDBDs be used for design work as design inputs?

17. Is heater interlock DH-019-LS. safety related? If not, what is the effect of its failure prior to an accident? (Ref. DHR EDBD, Section 3.0).

18. Pump design flow is 3,000 gpm at 350 feet. The pumps must attain rated flow within 10 seconds. What are the IST acceptance criteria? (Ref.DHR EDBD, Section 3.0).

19. How is the cumulative time of 2 hours at 80 gpm (DHR pump minimum flow) monitored? Is there historical data on the cumulative time? (Ref.DHR EDBD, Section 3.0)

20. How are the valve positions controlled for valves DHV-110 & DHV-111? Do they receive an auto signal to open? Is there an LCO if they are closed? If not, what is the time delay ? Will they be able to open in time to support the 35 seconds requirement to achieve the low pressure injection? (Ref. DHR EDBD, Section 3.0).

21. Does calculation II-A-3 demonstrate conformance with the Regulatory Guide 1.1? (e.g. 0.2 ft/sec at 50% blocked screen?) Please provide a copy of the calculation (Ref. DHR EDBD, Section 3.0).

22. For temporary change EDBD TC No. 388 dated 7/11/95, it appears that the same person prepared and reviewed EDBD. Is this permissible per the QA program? Are valves DHV-7 and DHV-8 referenced in the EOPs and in the GL 89-10 program? Please provide a copy of PR 95-0083.

23. How was the temporary change EDBD TC No. 491 dated 3/21/96 incorporated in the OPs, AOPs, EOPs?

24. What are the means of protection to prevent DHR & BS pumps operation without cooling?

24. Provide the following information pertaining to calculation M-83-0001, Revision 3; RB Spray and ECCS Storage Tanks Drawdown Analysis:

    Did the switchover from BST-2 to BST-1 take place? Was there a 10 CFR 50.59 evaluation to support this change? If yes, provide copy.

    What is the impact on the potential iodine dose following a large break LOCA? It appears that the existing analyses were based on an incorrectly modelled piping resistances. Was the effect of this discrepancy evaluated for the existing plant configuration?

    What is the resolution of the SBLOCA? Does this issue apply to the existing analysis? (BWNS Letter dated May 21, 1990, FPC-90-409).

    What are the (actual) NaOH concentration and level. How are they maintained?

    Provide justification for the minimum and maximum BWST volume used in the calculation.

25. Provide the following information pertaining to calculation M-89-1023, Revision 2; BWST Level Information for use in Establishing Tube Rupture Alternate Control Criteria

    How were the results of this analysis incorporated into the plant operations?

    Are there procedures in place to prevent the operators from manually initiating the building spray for this event?

    Can the drop line opening be credited for this event?

    It appears that no analysis were performed to establish the ability to meet the pH limits specified in the Technical Specification Bases nor established a positive means of pH control.

    What is the basis for LPI flow equal to 1,000 gpm? How is it controlled?

Is there a parametric study or other evaluations to support the position that the instrument uncertainty associated with flow indication need not be considered?

What is basis for the temperature correction difference?

It appears, that assumption No. 1 requires validation. Without the validation, 29.99 psig will be a more appropriate final pressure. Also what is the Technical Specification limit for the RB air temperature? If it is greater than the 100°F used in the calculation, the flash fraction calculation may not be conservative.

The portion of the calculation that discussed cooldown of the RCS was based on the FSAR data. How did Crystal River implement the ANSI N.45.2.11 requirements for use of the validated design inputs?

Did the information in Attachment 2 (Filling the Generators and MS Lines) receive an independent verification?

What are the references used for the RB flood level volumes used in this portion of calculation?

26. Provide the following information pertaining to calculation M-90-0021, Revision 6; Building Spray Pump and Decay Heat Pump NPSH

Provide the 10 CFR 50.59 evaluation performed for this calculation?

What are the DH, BS and MU flow rates used in Chapter 14 analysis?

Does the BS flow rate value include the entire loop error, including the ability of the operator to set the exact value of 1200 gpm?

Is the MU flow for each leg measured or calculated? How is it controlled during the accident?

What is the basis for 100 gpm recirculation flow?

Is the operation of both MU pumps piggy-backed to one DH pump precluded (Revision 5). How?

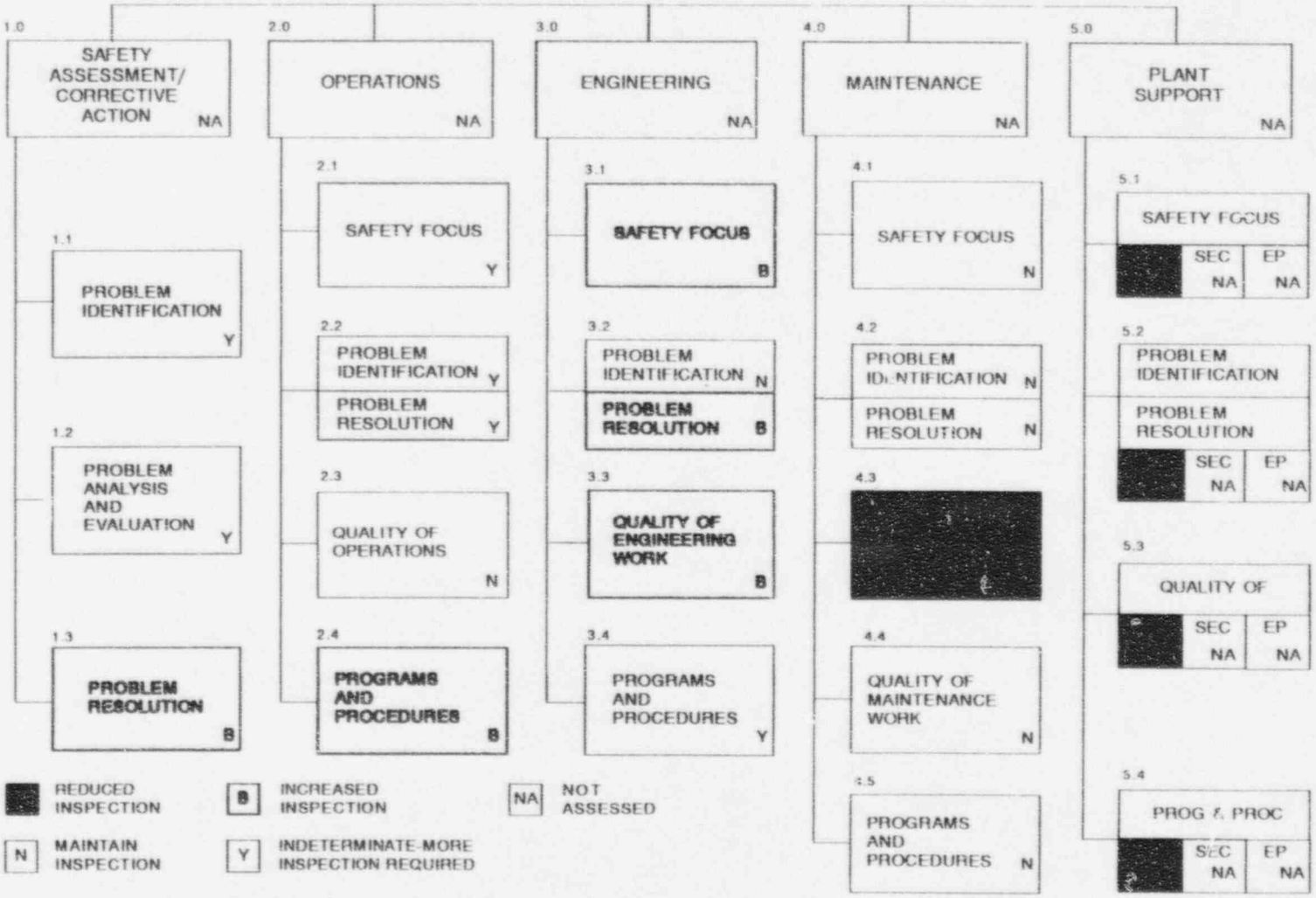
Was the EOP-290 revised? (Revision 0, assumption not requiring method No. 1).

Did Crystal River evaluate acceptability of use of BSV-1 and BSV-8? (Revision 0, assumption not requiring method No. 5).

Please clarify reference to test data in method No. 11 (Revision 0).

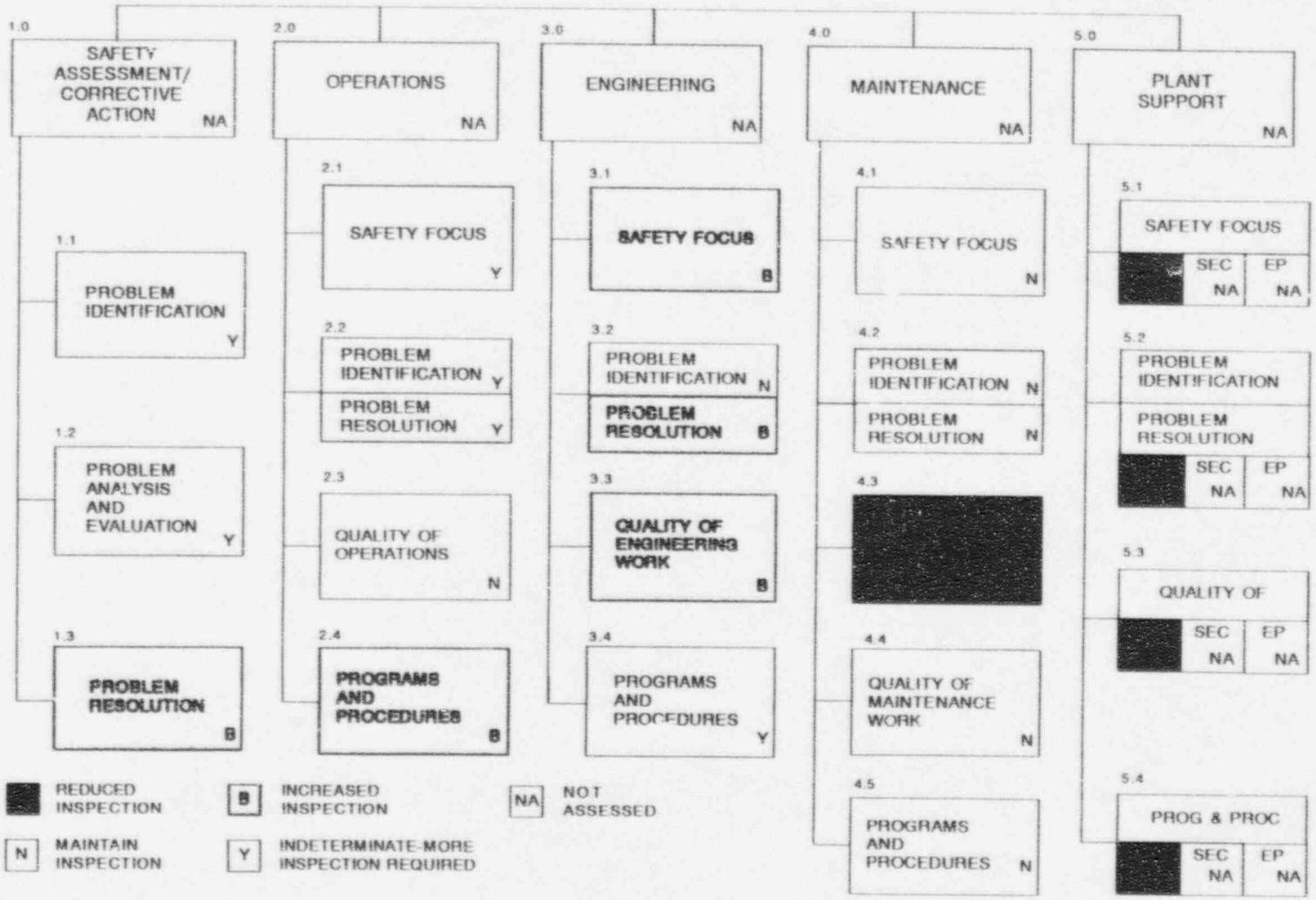
CRYSTAL RIVER UNIT 3

PRELIMINARY PERFORMANCE ASSESSMENT/INSPECTION PLANNING TREE



CRYSTAL RIVER UNIT 3

PRELIMINARY PERFORMANCE ASSESSMENT/INSPECTION PLANNING TREE



APPENDIX C